Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety
Public Meeting on Distribution Integrity Management
September 21, 2005

Summary

PHMSA's Office of Pipeline Safety conducted a public meeting on September 21, 2005, in Dallas, TX, to discuss the issue of assuring integrity of natural gas distribution pipeline systems. Over the past several years, PHMSA has implemented new integrity management regulations for other gas and hazardous liquid transmission pipelines. Subsequently, PHMSA has been engaged in a Distribution Integrity Management Program (DIMP), in cooperation with industry, state pipeline safety regulators, and members of the public, to evaluate how the principles of integrity management can be applied to natural gas distribution pipelines. The purpose of this meeting was to describe the activities of this program and its likely conclusions and to solicit input from other members of industry and the public.

The discussions at this meeting are summarized below. If viewed electronically via the PHMSA/OPS Distribution Integrity Management Information System web site, links in this document will open presentations or statements used by the presenter.

<u>Opening Remarks</u>

<u>*Welcome – Brigham McCown, Acting Administrator, PHMSA*</u>

Mr. McCown is the recently-appointed Deputy Administrator of PHMSA and is currently also Acting Administrator. He noted that while DOT has been in the pipeline business for a while, PHMSA is new. PHMSA is taking a look at what it does, how to apply new technologies and what other changes might be appropriate. Public meetings are an integral component of the PHMSA strategy.

Safety is vitally important to distribution pipelines, because those pipelines are located where people live and work. There is significant diversity among distribution pipeline operators and systems. There are significant differences in design of these systems compared to other pipeline types that are covered by the existing integrity management regulations. In addition, PHMSA recognizes the vital role played by the states, which exercise regulatory authority over most distribution pipeline operators. It is important to take these differences into account in deciding how to implement integrity management principles for distribution pipelines. The participation of states and industry in this effort is welcome.

<u>*Introduction – Stacey Gerard*</u>

The successful implementation of integrity management (IM) regulations for other pipeline types is resulting in safety improvements. This success came to the attention of the DOT Inspector General (IG) and to Congress. Congress adopted the idea that the elements and principles of integrity management should have some benefit for distribution pipelines. This is the impetus behind the current program. Everyone recognizes that there are differences between distribution pipelines and those now subject to integrity management requirements, but all want to see how the principles can be applied.

In addition, the NTSB has renewed its challenge on excess flow valves (EFVs). Firefighter organizations have also become involved in this regard, writing to DOT Secretary Mineta encouraging that EFVs be required. This is an unusual focus on a single mitigative measure.

PHMSA, with NAPSR/NARUC, has put together a broad program to evaluate the application of IM principles to distribution pipeline systems. The participants in this program have, themselves, engaged additional resources to bring an impressive amount of expertise to bear. The program has four separate working groups:

- Strategic Options
- Risk Control Practices
- Excavation Damage Prevention
- Data

The purpose of this meeting is to hear a progress report and to try to narrow the gaps by drilling down on areas where there are divisions. This is phase 1. The result will be a report that will be part of the basis for PHMSA to move forward. PHMSA will take up the effort in phase 2, probably in January 2006. What will happen is not yet clear. We are looking at how to solve the problem. It may be a rule, legislation, education programs, or something else, or several of these in combination.

There seems to be a consensus that any rule should be flexible and performance-based. There is recognition that states have existing programs, and that consensus organizations are developing standards. The recent approval of three-digit dialing, 811, for nationwide excavation one-call is a big part of the solution. New technology will also play a role.

The diversity among operators, system designs, and materials is significant. That diversity drives the need for flexibility. Still, it is important to understand how the principles of integrity management can be applied, and that is the major focus here.

Assessing risk should be reasonably consistent for all operators. That identifies integrity issues. Risk mitigation options are what to do about integrity issues. This is where the major differences arise. Damage prevention programs will play a big role. Leak management and pipe management also will be important. In addition, there is the specific issue of EFVs.

PHMSA held a public meeting on EFVs in June 2005. There was significant discussion and PHMSA is taking some heat for the preliminary position described there that EFVs should be treated as one element within distribution integrity management. We are definitely leaning that way. That would allow operators to look at their problems and decide what is needed. There is an open docket, however. If the public record fills with comments in favor of mandating EFV installation, that could drive our decision.

The report of this Phase 1 effort regarding distribution integrity management is expected in December. The issue will be discussed at the December meetings of the Technical Pipeline Safety Standards Committee (TPSSC), which will be an additional public discussion opportunity.

Characterization of Gas Distribution Operations and Regulations

Three State regulatory commissioners are involved in this effort, but were unable to attend this meeting. These are Don Mason (Ohio), Jeff Hatch-Miller (AZ), and Randy Bynum (AR). Each provided statements that were read into the record describing their perspectives. These statements and remarks by representatives of the American Gas Association and American Public Gas Association are summarized below.

Don Mason

State regulators are responsible for assuring safe utility services at fair prices. Maintaining balance is important. It is not appropriate to try to produce ultimate safety if that increases the costs to the point that the service becomes unaffordable. We should focus our efforts where they will result in the most benefit. In Ohio, that means outside force damage. Almost half of our incidents result from that cause. The implementation of three-digit dialing for one-call will help, but it's only a start. States need statutory and legal remedies and a more efficient ability to file liens against damagers. Reducing the instances of third-party damage would mean a substantial improvement in distribution pipeline safety.

Jeff Hatch-Miller

Arizona does not have a formal distribution integrity management program, but does address many of the related issues. Damage prevention is a major priority. The state has strong statutes and active enforcement. Arizona regulations provide a common standard for classification of leaks. We assist small operators, including master meter operators, in meeting the provisions of the regulations, including generic procedure plans and education as appropriate.

Randy Bynum

Part of our mission is maximizing customer value and enhancing the economic environment of Arkansas by ensuring safe, reliable and reasonably priced utility distribution service, including natural gas. In Arkansas, excluding master meter operators, the natural gas distribution infrastructure consists of 18,000 miles of mains and

653,000 services. Half of the pipeline is plastic, with the largest portion of the remaining half being coated steel. There is a small amount of cast-iron main.

Arkansas' pipeline safety regulations are organized similar to the federal regulations, and are more stringent in 24 sections. The Arkansas Commission has authority over four private operators, six municipal operators, and 182 master meter operators. Over 97 percent of the gas distribution facilities are operated by the four private operators, and thus the Commission's rate-setting authority has significant influence.

The small number of operators means that we interact on a regular basis. We can also take specific actions to help address integrity issues. In the case of one operator, this has included an aggressive program, with economic incentive, to replace all cast iron and bare steel pipe. This program is well under way, and is an example of the kind of specific actions that state Commissions can and do take to improve distribution system integrity.

Lori Traweek, American Gas Association

The dialog among stakeholders and the analysis of data in this program have both been unprecedented. This has helped all of us understand our systems and what can be done to improve their operation. It is important to review, at a high-level, what we have learned.

We've learned that there is considerable diversity in the material structure of our pipeline systems and that Regional differences also exist. This stands in stark contrast to the situation for transmission pipelines where the vast majority of pipeline mileage is cathodically protected steel.

The American Gas Foundation study, which was discussed at the first public meeting, found that the major cause of serious incidents – those that resulted in deaths and injuries – was outside force damage. DOT's study of all reported incidents, by Allegro, Inc., confirmed that conclusion.

The approach we take to distribution integrity requires a balance among public safety, reliability of service, and cost. We need to take into account differences in state distribution safety programs, the impact and likely effect of other recent OPS initiatives and mandates, and the current regulations. If we are to be successful, we must:

- Strengthen Excavation Damage Prevention Measures
- Provide Assurance that Leaks are being Managed Responsibly
- Address EFVs
- Call for an Integrity Management Plan that allows operators and regulators the flexibility to identify appropriate threats and implement appropriate risk control practices
- Identify meaningful performance measures

John Erickson, American Public Gas Association

Municipal utilities are different from investor-owned companies. One factor is size. For example, Atmos Energy is an investor-owned utility that covers much of Texas, has 1.47 million customers, $1.2 billion in annual sales and over 26,000 miles of main. By contrast, Winfield, KS has 5 thousand customers, $5.5 million in annual sales, and 91 miles of main. That's just an example. There are 977 utilities that are smaller than Winfield. These companies are performing well and making significant safety progress, but they must be treated differently. They shouldn't be excluded, but the differences in their capabilities and needs must be recognized. For instance, extensive risk analysis is probably not needed for their simple systems.

Cost recovery is also different for municipal utilities. The concepts of rate base and rate of return do not apply. Funds applied to improvements in the gas distribution system often come at the expense of other municipal services, including public safety. It is important that we not impose unnecessary costs, or we could produce a detrimental effect on overall public safety as a result of these tradeoffs.

Stacey Gerard

Ms. Gerard made comments in response to these characterizations. She noted that the speakers presented a very harmonious description of what we are doing. The problems, though, will not be in "what" but in "how" we accomplish things.

For example, we agree that we need to address EFVs, but "how" is the question. The question from the June meeting is how an operator's decision on use of EFVs is accountable. How is that decision reported, accounted and known? Without knowledge and accountability, we won't be successful. Where knowledge is needed is not clear. Perhaps inspections at the state level will be sufficient.

Leaks are another issue. There are leaks of different kinds. Some need to be addressed. Some do not. We need to describe this situation better. We need to answer the question of whether the infrastructure is well managed.

With respect to excavation damage, everyone agrees that we can't make significant improvement without addressing this threat. We already have lots of programs, but the problem is still large. There is a growing sentiment for the law to change, to make it easier to use civil authority to address this problem. The excavator community is very involved in enforcement. That's important. If the entire community doesn't support what we do, it can't happen.

The DOT IG raised the question to Congress of the need to apply IM principles in distribution. Congress acted very quickly to require a plan of OPS in a mere five months. Congress has the full expectation that we will implement that plan, and will apply IM principles in this area. We are now in the beginning of a reauthorization cycle. If we don't deal appropriately with this question, and perhaps even if we do, Congress may take up its pen and provide direction.

Ms. Gerard encouraged attendees to provide comments to the open docket to help identify how we should proceed.

Plan and Process of the DIMP Effort

Mike Israni

Mike Israni summarized the background of this effort. Pipeline transport of natural gas is very safe, but high-consequence incidents still happen. The previous integrity management rules were, in part, a response to two such incidents, at Bellingham, WA, in 1999 and Carlsbad, NM, in 2000. OPS recognizes that distribution pipelines present unique challenges and that the rules applied to other pipelines cannot simply be made applicable here. Still, the basic principles can apply.

As Ms. Gerard commented, Congress has taken a particular interest in this subject. They have asked DOT for a plan, which was submitted to them in June. PHMSA needs to respond to this Congressional interest. New actions are needed. That will mean new burdens on operators. PHMSA wants to be efficient, effective, and not overly burdensome. Cost recovery is recognized as important, but it is not an issue for the federal government.

Mr. Israni noted that detailed information about this program, including information from the previous public meetings, is available on a public web site. That site can be reached from a link on the OPS home page (http://ops.dot.gov).

Glynn Blanton

Glynn Blanton, chair of the DIMP Coordinating Group, described the structure of the work/study groups and the participating stakeholders.

This is a program that has involved active communication. Information and comments have passed both up and down the organizational chain. Executive oversight is provided by a Steering Group consisting of State regulatory commissioners, senior representatives of AGA and APGA, executive managers of operating utilities, representatives of the public, and PHMSA/OPS management. Direct oversight is provided by the Coordinating Group comprised of state pipeline safety program managers and managers from AGA and APGA. The heart of the program consists of the four work/study groups.

Each work/study group consists of representatives of state pipeline safety programs and investor-owned and municipal utilities. Public representatives, including firefighter and excavator groups, also participate on work/study groups.

Ed Steele

Ed Steele, NAPSR Chairman and member of the Coordinating Group, described the results to date.

The early work in Phase 1 resulted in agreement on the options to be pursued. Options selected included: a high-level flexible rule, additional guidance, a nationwide education program (based on implementation of 811 dialing for one-call), and continued research and development (industry and PHMSA funding). Options considered but not selected included: model state legislation, guidance for mandatory adoption by states, and a prescriptive federal rule.

Further discussion has resulted in agreement on the basic elements of a distribution integrity management plan. Those are:

- a formal written plan (often integrating what already exists)
- understanding the infrastructure in an operator's system
- assessing the risks
- addressing the threats and risks
- monitoring performance and adjusting as needed
- reporting a subset of results to regulatory authorities

49 CFR 192.613, Continuing Surveillance, is similar in many respects. It is possible that IM requirements will build on this existing regulation.

Don Martin

Don Martin, Vice Chair of NAPSR, described likely outcomes. There is some uncertainty in these because discussions are still underway. In particular, specific risk control practices have not been agreed upon.

There is general recognition that reducing the risk from excavation damage requires actions that are outside of PHMSA's regulatory jursidiction. One-call systems exist, but enforcement is spotty. The data shows that active enforcement of one-call requirements leads to greater effectiveness.

While the external damage threat is large, more than half of all incidents result from other causes. Those causes are threats more under the control of operators. Early consideration of actions that could address those threats include: leak classification and management, pipe replacement, eliminating inactive service lines, and monitoring pipe condition.

The basic structure of an integrity management program is reflected in a graphic that is included as Attachment A to this summary.

Questions and Comments

Hans Mertens, VT Public Service Commission, expressed concerns about the potential costs, and resulting benefits, of new IM requirements. He noted that no one had discussed the business model for gas operators, how this will fit, and how it will continue to support what is already a safe and efficient system. Mr. Mertens suggested that we should be focusing much more significantly on the major threat and less on the minor. He further suggested that it may be necessary to respond to Congressional interest by explaining the current safety of the gas distribution network and that limited or no additional action is required.

<u>Task Group Objectives, Approach, and Anticipated Products</u>

The chairs of each of the four work/study groups provided a brief report describing their respective group's objectives, participants and activities.

<u>Data Group, Michael Thompson</u>

The mission of the Data Group is to evaluate existing data and collect more data as needed to identify the nature, significance, and trends in threats affecting distribution pipeline systems and the effectiveness of current programs in addressing these threats. The principal data sources used in group activities are the DOT database of incident reports and annual reports (principally data on leaks removed). Each has certain limitations.

The group has attempted to characterize the baseline level of gas distribution safety. This baseline can be characterized based on three factors: incidents, leaks, and physical system characteristics (e.g., miles of material with increased leakage potential). The dominant cause of incidents is excavation damage, with the next leading causes being other outside force and natural forces. Leaks, on the other hand, are primarily caused by corrosion while the second and third causes are excavation damage and material/welds.

The American Gas Foundation (AGF), in its 2004 study, found that there has been a downward trend in incidents resulting in death and injury, and in the number of such incidents caused by excavation damage, over the 13-year period studied (1990-2002). AGF found no statistically-significant trend for the total number of incidents over this same period.

The Data Group found weak downward trends in leaks removed due to corrosion and third-party damage. The Group also identified a downward trend in the mileage of certain materials that are more prone to leakage. Limitations in the data made further analysis difficult. The Group considers that changes in data reporting could be useful, including additional information when the cause of a leak or incident is excavation damage (considering CGA's Damage Information Reporting Tool, DIRT, and state reporting forms for the kind of information that could be useful), adding material type to leak reports, and separately reporting hazardous leaks removed.

The Data Group also considered available information on Excess Flow Valves. From the available data, the Group concludes that EFVs work reliably if specified and installed properly. EFVs are not appropriate for many gas services, since they operate at low pressures. Additional data gathering is still in progress concerning the performance of installed valves.

Leak data leads to a conclusion that there is no clear basis for excluding operators of any size from any new IM requirements – i.e., there is no size threshold below which safety performance is notably different. In fact, it is difficult to define size groupings on which performance can be analyzed, since the vast majority of gas distribution operators fall in the smallest size category for any reasonable breakdown. Master meter operators and LPG operators, do not file annual reports with leak data, however, and thus the applicability of this conclusion to these groups of operators is uncertain.

Excavation Damage Prevention Group, Bruce Paskett

The objective of the Excavation Damage Prevention Group is to devise a plan to enhance natural gas distribution pipeline safety by significantly reducing excavation damages. Excavation damage is the most significant threat facing gas distribution systems. This threat must be addressed if significant improvements in safety are to be made. Doing so is difficult, though, since it is most often not under the control of the operator.

The Group evaluated available data, and focused primarily on the effect of comprehensive state programs, those including active enforcement. The trend in reduction of excavation damage leaks removed is more significant for states with comprehensive programs than for those without. The difference is more noticeable if the number of leaks is normalized to 1000 locate tickets. Minnesota and Virginia are examples of states where enforcement appears to have resulted in a significant downward trend in damages.

The Group finds:

- States with comprehensive damage prevention programs have a significantly lower risk of excavation damage and the potential for incidents.
- The elements of a comprehensive damage prevention program include:
    - Enhanced communication between operators and excavators
    - Fostering support and partnership of all stakeholders in all phases (enforcement, public education, etc.) of the program
    - Operator’s use of performance measures regarding persons performing location and pipeline construction
    - Partnership in employee training
    - Partnership in public education
    - Enforcement agency’s role as a partner and facilitator to help resolve issues
    - Fair and consistent enforcement of the law to all stakeholders

  - Use of technology to improve all parts of the process
  - Analysis of data to continually evaluate/improve program effectiveness
- Incentives should be provided to operators, excavators, and locators for compliance with the damage prevention program requirements. (Specific incentives should be determined by individual stakeholders).
- Operators should review and implement CGA Best Practices and other practices as appropriate to help reduce damage to their facilities, such as: trend analysis, root cause analysis, accurate location records, participation in pre-project/pre-bid meetings, marking location of newly "in service" lines at ongoing construction sites, and effective damage claims program
- Damage prevention program metrics should be provided to OPS in addition to current data on the annual report as a measure of distribution safety. These include: damages (as defined) and damage ratio (damages per 1000 tickets)
- Operators should track metrics for internal use for damage prevention program evaluation

The Group notes that enforcement is not an end in itself. It is a tool to assure that all stakeholders participate in reducing the instances of excavation damage.

Risk Control Practices Group, Phil Sher

The Risk Control Practices Group accepted the characterization of eight threat categories used in OPS incident and annual reports. The Group considered all of the categories except excavation damage, which was considered by the Excavation Damage Prevention Group.

The Group considered how an operator would evaluate and prioritize threats. This should include all relevant system characteristics and environmental factors. The operator should also consider its failure history. The wide diversity among operators makes it impractical to prescribe a specific method for evaluating and prioritizing threats. Simple methods may be acceptable. Probability and consequences should both be considered.

Each operator must then select risk control practices based on its threat prioritization. Again, it is not practical to specify practices since the issues faced by operators differ. The Group will document in its report a list of suggested practices. Among these is an approach to leak management that can be described as:

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

The Group also evaluated existing regulations and guidance to identify where changes are needed. Regulatory changes will be needed to require an overall approach to management of distribution integrity. Additional guidance will likely be appropriate, including specific guidance that can be used by smaller operators.

Performance measures are an important part of a formal integrity management program. Some measures are likely to be useful on a national basis. The numbers of incidents, deaths, injuries, and property damages have been available as national measures and will continue to be used for this purpose. Other potential national measures include the status of operators in implementing DIM programs, the status of operators in meeting the criteria for an effective leak management program, and the amount and ratio of state-of-the-art pipe (i.e., pipe that an operator would elect to install today) in a system. The number of leaks may also be useful on a national basis.

Additional measures are likely to be valuable at a company level. These would depend on the particular circumstances and threats for each operator, but should be an integral part of any IM program. Periodic review and self-assessment is important, and performance measures can play a role in this area.

Strategic Options Group, Jim Anderson

The mission of the Strategic Options Group is to 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.

The Group was responsible for evaluating various options for addressing the integrity management issue. These have been described earlier. The principal option chosen is a high-level, flexible federal rule, with additional guidance as needed, to be implemented under the existing (generally state) regulatory authority.

The Group also considered the elements appropriate for a DIM program. Again, this has been described earlier and is detailed in the graphical presentation in Attachment A.

The Group is considering a finding that pipeline operating between 20 and 30 percent of the specified minimum yield strength (SMYS) should be treated under distribution integrity management requirements. Such pipeline is, by definition, treated as transmission pipeline under the regulations. As such, it is currently subject to the integrity management requirements applicable to transmission pipelines (Subpart O). Those requirements themselves, however, include some different treatment for low-pressure pipelines, because they tend to fail by leakage, as do distribution pipelines, instead of rupture. The Group is considering whether it would be more appropriate to provide an option for this pipeline to be treated under distribution integrity management requirements, once they are in place.

The Group has also concluded that EFVs should be a mitigative option to be implemented under an operator's DIM program. EFVs meeting performance criteria in

49 CFR 192.381 and installed per §192.383 may reduce the need for other mitigation options. The Group concludes that it is not appropriate to mandate excess flow valves (EFV) as part of a high-level, flexible regulatory requirement, since an EFV is only one of many potential mitigation options. While this is the majority conclusion of the Group, there is a minority view that installation of EFVs should be mandated for new and renewed services where conditions are such that the valves will function.

Questions and Comments

Don Stursma asked what the Excavation Damage Prevention group considers an effective/ineffective damage prevention program. Bruce Paskett responded that a program containing the nine elements outlined in the Group's slides is considered effective. (The elements are listed in the summary above)

Rick Kuprewicz commented on the appropriateness of one-call exemptions. This issue has also been discussed by the Technical Pipeline Safety Standards Committee (TPSSC), of which he is a member. He concludes that there should be no exemptions from one-call notification requirements. Bruce Paskett noted that the Excavation Damage Prevention Group reached the same consensus.

Stacey Gerard asked Mr. Paskett to discuss the options considered in areas where states would need to take action. Mr. Paskett responded that the Group had discussed the possibility of federal legislation to give DOT authority over excavations near pipelines. They concluded this was not practical. They are considering suggesting legislation that would give state pipeline safety programs authority, while providing additional funding that would be considered "seed" money. This is modeled after the Virginia program. Ms. Gerard asked additional questions regarding the funding concept, and Mr. Paskett emphasized that what is under consideration would be separate from current funding programs.

Hans Mertens commented that State support for funds would be difficult or impossible. If additional requirements are going to be levied, they need to be a fully-funded mandate. He also encouraged that guidance materials be made available in advance of implementation of the rule, since trying to implement a rule while guidance is being developed would be inefficient and confusing. Finally, Mr. Mertens noted that enforcement of one-call violations can be difficult, because there are no "bright-line" tests. Failure to call is straightforward, but other "problems" are much more subjective.

A representative of the Gas Technology Institute (GTI) noted that there is a need to assure that data being considered has integrity. He also noted that the metrics proposed by the Excavation Damage Prevention Group would require a definition of the term "ticket". Bruce Paskett responded that the group has defined "ticket".

Blaine Keener questioned the perceived value of national consensus standards for grading and responding to leaks. Phil Sher responded that one question is the meaning of a trend in leaks. Is finding more leaks good, because an operator is looking harder, or is it bad, because performance is decreasing. There are inconsistencies in the data currently because operators are only required to report leaks that are "removed". At the same time, imposing a consistent standard on operators would increase costs without obvious benefits.

Stacey Gerard asked if it would be possible to develop a qualitative scale for state inspectors to use for leaks, in the manner of the existing integrity management protocols. For example, this could consider the 5 elements of the LEAKS program suggested by the Risk Control Practices Group. States could report the percent of operators with "passing" performance on leak management. Phil Sher noted that his Group had considered self-reporting by operators regarding whether they had met the 5 elements. He agreed that States will be evaluating operators, but the nature of this evaluation has not been considered. Jim Anderson added that state "grading" would be very subjective; it would be hard to assure consistency.

Excess Flow Valves

Mike Israni provided a background discussion on EFVs. There are some valves that manufacturers state will work below 10 psig pressure, but there is very little data concerning their performance. Current standards address applications above 10 psig, and that is what is being considered in this program. EFVs installed in such services address the threats of earth movement, excavation (including yard work by homeowners) and vehicle impact with meters. EFVs do not provide any protection against breaks downstream of the meter.

49 CFR 192.381 specifies performance standards for EFVs, for services operating above 10 psig. 49 CFR 192.383 requires that operators notify customers for new and renewed services of the availability and benefits of an EFV, and that an operator must install the valve if the customer agrees to pay for it. Operators can decide to install EFVs voluntarily on all new and renewed services where conditions are feasible, and then need not notify customers.

The Executive Steering Group has expressed a preference to consider EFVs in the context of distribution integrity management requirements. The basis for this preference is that EFVs are but one mitigative tool among many.

Based on a number of recent surveys, PHMSA understands:

- States do not collect data on performance (incidents prevented or false closure)
- The rate of false closures appears to be low (from limited information)
- No State currently requires installation or is considering such a requirement
- All or large percentage of operators install voluntarily in 16 states, mostly Eastern
- No operators install voluntarily in 9 states, mostly Western
- Larger operators seem more likely to install voluntarily
- Small percentage (about 2 percent) of installed valves are result of customer notifications

PHMSA funded a review of five years of incident data by Allegro, Inc., to determine the percentage of incidents in which EFVs could have been beneficial. There were 634 incidents reported during the period analyzed. Of these, 101 (16 percent) could potentially have been averted if an EFV were present. The major causes of these incidents were excavation and vehicular damage. This is an upper bound estimate, as limitations of the data precluded drilling down further.

PHMSA conducted a public meeting on the subject of EFVs on June 17, 2005. There was general agreement at that meeting that EFVs are not appropriate under all conditions and that their use should not be mandated under circumstances in which they will not perform reliably. There was no agreement on whether EFV installation should be mandated in all new and replaced services where conditions make them feasible or whether they should be treated as one among many mitigation options. There also was no agreement as to whether costs to install EFVs in instances in which they are feasible are more or less than the administrative costs associated with complying with current notification requirements.

Additional data gathering is ongoing, and changes to incident report forms that would make more data available regarding the effectiveness of EFVs are under consideration. A clearinghouse for EFV information is available on the web, at www.cycla.com/dimp. This clearinghouse can be reached from the OPS web site (http://ops.dot.gov) by selecting Integrity Management and then Distribution Integrity Management.

Jim Anderson suggested a regulatory treatment for the EFV issue. He suggested that an operator's IM plan must reference the installation of EFVs. If an operator determines, based on risk assessment, that an EFV is needed, it must install the valves. Mr. Anderson suggested that the requirement could specify factors that an operator must consider in its risk assessment, similar to the requirement in Subpart O for analysis and installation of remote/automatic shutoff valves for transmission lines.

Stacey Gerard noted that there are other factors that must be considered in deciding what to do about EFVs. The National Transportation Safety Board (NTSB) has taken an advocacy role in this issue. They had previously recommended that EFVs be required, and expected that additional data would be available later. That data was not collected, owing in part to the promulgation of 192.381 and 383. In the meantime, EFV performance has improved and costs have decreased. This has resulted in a hardening of the position of those advocating required use of EFVs. The fire service community definitely sees EFVs as valuable. The International Associations of Fire Chiefs and Fire Fighters have been advocating this issue in Congress.

Ms. Gerard noted that Senator Biden's office recently called her to Capitol Hill to discuss the issue. The Senator's staff was very knowledgeable about current efforts. They question whether the option of treating EFVs under DIM would have teeth. Ms. Gerard would like to find some way to say that an operator must consider a number of factors and must install if an EFV is needed. PHMSA needs to work from the record, however, and the record at present is not clear. Attendees were invited to submit comments for the record.

Mr. Israni noted that PHMSA is considering a requirement that operators document their decision process if they decide not to install. In some past meetings, this has been discussed as a requirement to submit. At this point, the preferred option appears to be that the documentation be available for inspection rather than be submitted.

Questions and Comments

Lori Traweek noted her conclusion that a requirement similar to that suggested by Jim Anderson would accomplish what is desired. It would require that operators formally analyze the need for an EFV. She would want to assure that operators who are already voluntarily installing EFVs would not need to do more. She does not support the concept of requiring an operator to submit its decision process, believing it would be a bad precedent. Operators make decisions all the time and should not be expected to have to justify them for selected issues. A survey could be conducted – of states or operators – after a period of time to indicate the effect of a new requirement. Ms. Gerard asked if an additional question on the annual report might substitute for surveys. Ms. Traweek responded that an additional question would not necessarily be a problem but asked how useful it would be. Information now reported in the annual report is data. The suggested question would go to a change in operator position. Treatment could be problematic. Ms. Gerard noted that PHMSA will need to answer questions about the efficacy of a performance-based rule.

George Mosinskis noted that there is a liability issue with a requirement to document a decision basis. A survey has an advantage in that regard. He also commented that there is a need to assure that language such as that suggested by Jim Anderson be consistent with current regulations, in terms of the criteria specified. Ms. Gerard noted that litigation concerns are a poor justification for not documenting things. Integrity Management experience for other pipeline types is demonstrating that writing things down is important.

Rick Kuprewicz commented that it is important not to lose sight of the objective. He sees a risk analysis approach as real world. The burden is on the operator. It is not that complicated. There are mechanisms in the existing IM audit review process to find concerns.

<u>Views from Industry and Trade Associations</u>

<u>AGA, Chris Beschler</u>

The incidents that operators have the ability to control are few and there is no increasing trend. Where incidents are increasing are areas where operators have a limited ability to control (e.g., third-party damage).

Excavation damage produces the most incidents, but few leaks. Corrosion is the cause of the majority of leaks, but results in few incidents. Thus, a national leak database may not have meaning. Current experience demonstrates that leak management programs are working. Thus, the industry perspective is that there is a need to reduce excavation damage incidents and enhance the confidence in leak management.

Reducing excavation damage will require ways to convince excavators that there are benefits to them, to their business models, and to their employees. There is a need to reach out to that community and to leverage the resources of the Common Ground Alliance.

The value of an inventory of state-of-the-art pipe is not clear. Such an inventory could lead to arbitrary decisions to replace pipe. Such decisions should be based on risk. Current replacement decisions are based on factors including safety and resource availability. Operators analyze these factors and rank their pipe to see where replacement would have the most effect. Leak management programs often can be improved as an alternative to replacement, resulting in older, non-state-of-the-art pipe performing well for many years.

The industry sees distribution integrity management as a high-level requirement with flexibility for operators and regulators and meaningful performance measures so that all can see the effect.

APGA, John Erickson

Mr. Erickson supported the remarks of Mr. Beschler. He noted that many operators already have integrity management programs. Winfield, KS, for example, knows their infrastructure and they are working on their problem area (bare steel). They have performance measures. They are becoming overwhelmed with new requirements, for public awareness, operator qualification, and integrity management. They are also affected by demands for other city services.

APGA considers that Subpart O-like requirements to write and maintain integrity management plans would overwhelm small municipal operators. For small systems, there are limited differences in risk. There are no resources, nor need, to do complex statistical analyses. Guidance is needed for small operators to make implementing integrity management practical. The guidance should be of the nature that "if your system meets these criteria, then do this."

Winfield, KS also can help inform the decision on EFVs. They have installed about 50 EFVs as a result of customer notifications. Customers are charged $50 for an installation. They recently had an instance in which an operator damaged a service line, did not report it, and covered up the problem and left the scene. This kind of event has been reported elsewhere where EFVs are used, and will need to be addressed, perhaps as part of an education program. APGA sees risk analysis as a reasonable means to approach the decision on use of EFVs. It should be acceptable, however, for analyses to be performed on a system-wide basis.

City of Mesa, Mike Comstock

Mesa's experience with EFVs is similar to Winfield's. The city has had 2 reportable incidents. They charge $80 for an installation and have installed 20 EFVs. They have had one event where a contractor hit a line and did not even know they had damaged a gas service. The residence was a winter visitor, and no one was at home to know that gas service had been interrupted. The problem was only identified by a neighbor noticing the smell of gas.

Mr. Comstock believes that the risk assessment we are looking for needs to be simple. There needs to be some means to group services to deal with it generically. Still, treatment of EFVs across the distribution industry is not likely to be uniform.

Excavation damage is the most important threat. Mesa is seeing about 150 damages a year. These damages occur on both mains and services, but a majority is on services. That number needs to be reduced. Doing so will require a partnership with other stakeholders involved in excavation and with other operators of underground utilities.

Views from Executive Steering Group on Issues

Commissioner Jeff Hatch-Miller

Commissioner Hatch-Miller's statement, presented by Glynn Blanton, provided the following positions on issues for which different positions have been advocated:

- EFVs should be treated as an option under DIM programs and not mandated
- Consistent standards for leak management would benefit operators with systems in multiple states, but there should be flexibility to handle unique situations
- The public should know, through existing operator publications, that leaks are quickly detected, repaired and reported as appropriate
- Treatment of potential consequences in risk assessments can be relatively simple, since most systems are entirely within a high consequence area. Still, recent experience with Hurricane Katrina shows that special attention is needed for populations not easily evacuated (e.g., hospitals, homes for the elderly or disabled)
- An effective one-call program requires a comprehensive set of rules and strong enforcement
- Master meter and small LP operators, and the smallest system operators, do not have the personnel and resources to develop manuals and training programs. Assistance/guidance is needed.

Commissioner Randy Bynum)

Commissioner Bynum's statement, presented by Don Martin, provided the following:

- EFVs should not be mandated, but should be treated as a part of an operators risk mitigation activities
- Leak performance data is an important metric for individual operators but is less useful at the national level, particularly if additional costs are imposed for operators to report this data in a form that allows that use
- He has concerns about the potential for requiring operators to detail potential consequences over many miles of distribution main. Pipeline safety standards already consider higher risk areas and that kind of treatment should be incorporated in IM
- It appears, from the findings of the Excavation Damage Prevention Group, that changes in damage prevention enforcement could be needed. Getting state legislatures to enact such requirements, particularly if it is an unfunded mandate, could be difficult
- It will be very difficult for master meter and LP operators to implement an IM program. The different scale of their operations should be considered and a longer implementation time frame should be provided
- Cost recovery is an issue that should be left for the states.

Lori Traweek and John Erickson supported Commissioner Bynum's statement and added no additional comments of their own.

Rick Kuprewicz

He finds AGA's 5 points (see Lori Traweek presentation above, page 4) to have merit.

He is concerned about how the cost of doing business is being treated. There are some activities that are just a part of normal business. If an operator cannot afford them, it should sell the company.

With respect to EFVs, Mr. Kuprewicz has published a paper for the Pipeline Safety Trust (www.pstrust.org). That paper recommends that installation be mandated under certain conditions – and it is important to look for the exclusions. He sees three "Ps" driving this issue: phantom damage prevention, plastic service lines (tendency for bigger holes), and pressure increases. If those factors exist, then the burden should be on the operator to prove that it doesn't need EFVs. Dealing with the question of their need via risk analysis is not unreasonable, but we need to keep this simple.

With respect to excavation damage, it is past time for enforcement to occur. At the same time, we cannot be too punitive in how it is applied. We need to avoid creating disincentives to participation in one-call activities.

Mike Comstock

Experience in Operator Qualification demonstrated that developing guidance up front would have reduced anxiety and problems associated with implementation. That lesson should be heeded here.

Views from Other Stakeholders

Common Ground Alliance, Bob Kipp

Mr. Kipp described the Common Ground Alliance, a cooperative effort of almost 1200 individual members and 135 organizations. The CGA Best Practices have become a standard for damage prevention, and have been cited by NTSB in its investigations. They include Compliance and Enforcement practices.

The excavator community is heavily involved in CGA activities and Mr. Kipp considers them "on board" for integrity management. They are the ones who are getting killed. Experience shows that utility locates are done in a timelier manner in states with comprehensive damage prevention programs. Locates are more accurate when locators are properly trained. Safety is improved and costs and stand down time are reduced in these circumstances. Thus, excavators support comprehensive programs. They are receptive to initiatives that would improve safety and efficiency. No one "wants" to cause damage, but all are subject to pressures.

At the same time, there are tens of thousands of excavators. Mr. Kipp cautions that it is hard to address them as a "group" with homogeneous goals and actions.

CGA's data support the value of enforcement. There are differing models. The Minnesota program practices a top-down approach. Virginia, on the other hand, works through an advisory council. Fines are based on damages and those hearing appeals include peers. The Virginia program is non-adversarial. In both states, though, the trend in damages is improving and the incidence of damage is low.

Gas Pipeline Technology Committee (GPTC), Glen Armstrong

Mr. Armstrong chairs the Distribution Division of GPTC. The main objective of GPTC is providing guidance for implementing Parts 191 and 192. The committee has broad membership and operates under ANSI protocols. The guide is an ANSI standard, Z380.1. The Guide already covers most technical aspects of integrity management and recognizes the diversity among distribution operators and their systems.

A Guide appendix was drafted this year addressing the issue of integrity management directly. That appendix provides a framework for incorporating the results of this Phase 1 effort.

National Fire Protection Association (NFPA), Ted Lemoff

The mission of NFPA is to reduce the burden of fire on the quality of life by advocating scientifically-based consensus codes and standards, research, and education for fire and related safety issues. NFPA strongly supports the DIMP activities.

The discussion of operator diversity may not have gone far enough. Any rule in this area will cover trailer parks and other master meter and LP operators who have no resources. The systems of very small operators (<100 customers) are usually uniform. There is no need for analysis. A standard plan, or plans, is needed for these operators. A prescriptive option is needed for these smallest operators.

EFVs have one purpose. They will trip at the flow setting regardless of the problem. They will not trip if flow is below that setting, even if a significant failure exists. The data do not support a strong need for EFVs. If they are included in this program, the limitations of the valves should be recognized.

National Association of State Fire Marshals (NASFM), George Miller

Mr. Miller has previously described his position at the EFV public meeting and the NARUC national meeting. NASFM supports the fastest possible installation of EFVs. They understand the valves to be valuable to protect systems against catastrophes. Companies that have already voluntarily decided to install should be thanked. Other companies should be encouraged to make the same decision. While EFVs are valuable, they don't work in all systems. Slow leak problems would also still exist. Other approaches are needed as well. Enforcement of damage prevention is needed.

On balance, NASFM sees a comprehensive approach to distribution integrity management as justified. It is already working for liquid pipelines and gas transmission pipelines.

Questions and Comments

Don Martin stated that he understands that EFVs have been designed for application downstream of the meter. He asked if NFPA had ever considered including them in its code. Mr. Lemoff responded that there was a proposal to incorporate an EFV in each appliance connector as part of the 2006 update of the code. No one on the committee voted for it.

Jim Anderson made several comments:

- The NTSB definition of safety, being used in this program, considers costs. He expressed concerns about the costs that would be associated with new requirements and their effect on ratepayers.
- He is concerned about municipal utilities being driven out of business by costs.
- He is also concerned about the complexity of the likely rule.

- Master meter and LP operators will have limited ability to comply, and likely little need (benefit) in doing so. He suggested that master meter and LP operators may be exempted if no portion of their system is in a public place.
- He agrees that operators need a DIM plan and that it should be customized for their system.
- Reports required by the rule should be submitted to states.
- He encourages comprehensive damage prevention laws

Closing – Stacey Gerard

Ms. Gerard thanked those attending for their participation. She noted that much common ground had been reached. She encouraged attendees to provide additional comments to the docket or directly to the work/study group leaders. She especially invited comments on the 5 principal elements suggested by AGA (see page 4 above), EFV experience, concepts for risk analysis basis for EFV decisions, concept of leak management programs and the suggested LEAKS approach, performance measurement, and the overall approach to integrity management plans.

Attachment A