Written Testimony of
E. Frank Bender
Vice President Gas Distribution and New Business Division
Baltimore Gas and Electric Company

On Behalf of the American Gas Association
and
The American Public Gas Association

Before the U.S. House Energy and Commerce Committee
Subcommittee on Energy and Air Quality

Oversight Hearing on Pipeline Safety

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Good morning, Mr. Chairman and members of the Committee. I am pleased to appear before you today and wish to thank the Committee for calling this hearing on the important topic of pipeline safety. My name is Frank Bender. I am vice president of Gas Distribution and the New Business Division of Baltimore Gas and Electric Company, a subsidiary of Constellation Energy. BG&E delivers natural gas to 634,000 customers in an 800 square mile area in Baltimore and surrounding areas in Central Maryland. Our company is proud of its heritage as the first gas utility in the United States, tracing its history back to 1816.

I am here testifying today on behalf of the American Gas Association (AGA) and the American Public Gas Association (APGA). AGA represents 197 local energy utility companies that deliver natural gas to more than 56 million homes, businesses and industries throughout the United States. AGA member companies account for roughly 83 percent of all natural gas delivered by the nation's local natural gas distribution companies. AGA is an advocate for local natural gas utility companies and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international gas companies and industry associates.

APGA is the national, non-profit association of publicly owned natural gas distribution systems. APGA was formed in 1961, as a non-profit and non-partisan organization, and currently has 655 members in 36 states. Overall, there are approximately 950 municipally owned systems in the U.S. serving nearly five million customers. Publicly owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

I hope that my testimony will provide you with a better understanding of natural gas distribution systems, their regulatory setting, what is being done to further enhance their safety and how together we can build upon the excellent record of safety natural gas utilities have established.

The last reauthorization of pipeline safety resulted in several significant mandates and initiatives aimed at enhancing safety. Since the passage of that bill in 2002, the Pipelines and Hazardous Materials Safety Administration (PHMSA) and the industry have made significant progress on each of those initiatives, and the record shows that things are proceeding very well, with only a few minor adjustments to be considered. In fact, our companies have identified only one major area we believe requires considerable improvement: excavation damage prevention. Our companies believe your attention to more effective state excavation damage programs can, and will, result in real, measurable decreases in the number of incidents occurring on natural gas distribution pipelines each year. Although I will speak today on a number of issues the industry has considered in terms of further enhancing the safety record of natural gas pipelines, I will spend the majority of my time addressing excavation damage, which is the cause behind the majority of natural gas distribution pipeline incidents, and the need for Congress to provide an incentive for states to adopt stronger damage prevention programs.

Gas Distribution Utilities Serve The Customer

In order to understand how distribution safety can be enhanced, it is first important to understand the function and structure of distribution pipelines.

Distribution pipelines are operated by natural gas utilities, sometimes called "local distribution companies" or LDCs. The gas utility's distribution pipes are the last, critical link in the natural gas delivery chain. To most customers, their local utilities are the "face of the industry". Our customers see our name on their bills, our trucks in the streets and our company sponsorship of many civic initiatives. We live in the communities we serve and interact daily with our customers and with the state regulators who oversee pipeline safety. Consequently, we take very seriously the responsibility of continuing to deliver natural gas to our communities safely, reliably and affordably.

The Difference in "Pipelines"

Understandably, most customers lump all "pipelines" together, however, there are indeed significant differences between liquid transmission systems, natural gas transmission systems and natural gas distribution systems operated by local gas utilities. Each type of pipeline system faces different challenges, operating conditions and consequences of incidents.

Interstate transmission systems are generally long, straight runs of large diameter steel pipelines, operated at high volumes and high pressures. These larger transmission lines feed natural gas to the gas distribution utility systems.

Gas distribution utility systems, in contrast, are configured like spider webs, operate at much lower volumes and pressures and always carry gas that has been odorized for easy leak detection. Distribution pipeline systems exist in populated areas, which are predominantly urban or suburban.

Distribution pipelines are generally smaller in diameter (as small as 1/2 inch), operate at pressures ranging upward from under one pound per square inch, and are constructed of several kinds of materials including a large amount (over 40 percent) of non-corroding plastic pipe. Distribution pipelines also have frequent branch connections, since most customers require individual service lines. Most distribution systems are located under streets, roads, and sidewalks and, when working on them, care must be taken not to disrupt the flow of traffic and of commerce unnecessarily. Because distribution pipelines provide a direct feed to customers, the use of in-pipe inspection tools usually requires natural gas service to customers to be interrupted for a period of time.

Utility system customers play a unique role in identifying and reporting gas odors. At BG&E, our 610,000 customers serve as early alert systems, by monitoring for odors that may indicate an unsafe condition and promptly calling our call center. For these reasons, gas distribution utility systems are quite different from transmission systems.

Federal regulations recognize the differences between these types of pipelines, and different sets of rules have been created for each. 49 CFR Part 192 sets out the regulations for natural gas transmission and distribution pipelines and the rules distinguish between the two, while 49 CFR Part 195 sets out the regulations for liquid transmission lines.

Regulatory Authority

As part of an agreement with the federal government, most state pipeline safety authorities have primary responsibility for natural gas utilities as well as intrastate pipeline companies. However, state governments have to adopt as minimum standards the federal safety standards promulgated by the U.S. Department of Transportation

(DOT.) In exchange, DOT reimburses the state for up to 50% of its pipeline safety enforcement costs. Therefore, the actions of Congress affect state regulations and our companies. The states may also choose to adopt standards that are more stringent than the federal ones, and many have done so. BG&E and many other distribution system operators are in close contact with state pipeline safety inspectors. As a result of these interactions, distribution facilities are subject to more frequent and closer inspections than what is required by the pipeline safety regulations.

Natural Gas Utilities Are Committed to Safety

Our commitment to safety extends beyond government oversight. Indeed, safety is our top priority -- a source of pride and a matter of corporate policy for every company. These policies are carried out in specific and unique ways. Each company employs safety professionals, provides on-going employee evaluation and safety training, conducts rigorous system inspections, testing, and maintenance, repair and replacement programs, distributes public safety information, and complies with a wide range of federal and state safety regulations and requirements. Individual company efforts are supplemented by collaborative activities in the safety committees of regional and national trade organizations, such as the American Gas Association, the American Public Gas Association and the Interstate Natural Gas Association of America.

We continually refine our safety practices. Natural gas utilities spend an estimated $6.4 billion each year on safety-related activities. Approximately half of this money is spent in complying with federal and state regulations. The other half is spent for our companies' voluntary commitment to ensure that our systems are safe and that the communities we serve are protected.

Our industry's commitment to safety is borne out each year through the federal Bureau of Transportation Statistics' annual figures. Delivery of energy by pipeline is consistently the safest mode of energy transportation. Natural gas utilities are dedicated to continuing to improve on this record of safe and reliable delivery of natural gas to our customers.

What Are The Facts About Gas Distribution Safety Incidents?

As part of our commitment to safety, through the DOT pipeline statistic database gas utility trade associations monitor the number and causes of all reportable incidents on the nearly 2-million mile natural gas distribution system. An examination of DOT's statistics tells a tale of two trends.

A comparison of reportable incidents along the natural gas distribution system between 2001 and 2005 is depicted in the chart labeled Exhibit 1. The chart highlights the existence of two different types of incidents: those caused by factors the pipeline operator can directly control (such as improper welds, material defects, incorrect operation, corrosion or excavation damage by a utility contractor); and those caused by factors the pipeline has little or limited ability to control (such as excavation damage by a third party, earth movement, structure fires, floods, vandalism and lightning).

The record shows that between 2001 and 2005, 82 percent of all reported incidents were the result of excavation damage by a third party or other factors the utility company had little or no control over. The number of incidents operators could possibly control remained a small portion of overall incidents. In addition, statistics show that it is incidents caused by factors beyond the control of pipeline operators that are on the increase, with more reported incidents every year except 2002. (The dip in 2002 is attributed to a slowdown in construction-related activities associated with the post-9/11 downturn in the economy.)

In many cases, the typical “little or no control” incident involves a local excavator who has decided to expedite an excavation project at the calculated risk of hitting a line. The excavator’s actions, while irresponsible and risky, generally lie outside the jurisdiction of PHMSA. Given that willful negligence is generally difficult to prove and despite efforts by PHMSA, pipeline operators and others to educate excavators about the need for safe digging practices, third party excavation damage remains the single largest cause of incidents along the natural gas distribution system, accounting for almost half (48 percent) of incidents beyond the utility’s ability to control. Pipeline operators recognize the need to change this risky behavior in order to protect their lines and have used educational efforts to help raise awareness about the need for safe practices, but with a limited effect.

As the data demonstrates, the most effective way to minimize safety incidents on our distribution lines is to make incidents caused by excavation damage an endangered species. Congress has long recognized that excavation damage to gas and hazardous liquid pipelines is a major safety concern. This was the major reason for passage of damage prevention legislation passed in 1999 with the Transportation Equity Act of the 21st Century and in 2002 with the Pipeline Safety Improvement Act. These measures have made a substantial contribution toward decreasing the number of incidents**;** <u>but more can be done, with your continued support.</u>

<u>How Can the Distribution Integrity Process Affect Pipeline Safety Reauthorization?</u>

Since the passage of the 2002 Pipeline Safety Improvement Act, AGA and APGA member companies that also operate natural gas transmission pipelines have been resolutely implementing the requirements of the gas transmission integrity rule. It is a learning process for both operators and inspectors as together they proceed through the various steps of the implementation process. When PHMSA decided to promulgate the transmission rule, AGA and APGA stated that our members supported taking a responsible course of action in seeking to enhance transmission pipeline integrity. Our members continue to believe that such a course of action will yield safety benefits, as a result of the transmission integrity regulation.

Last year, PHMSA embarked on a new initiative to develop a regulation governing distribution integrity management programs (DIMP). Again, AGA and APGA member companies have fully supported taking a responsible course of action in seeking to enhance distribution pipeline integrity. As a starting point for distribution system regulation, PHMSA has followed the directives of the DOT Inspector General and the findings of a joint federal, state, industry and public stakeholder group that met for one year. Those findings are presented in the report *Integrity Management for Gas Distribution, Report of Phase 1 Investigations* released in December of 2005. The DIMP stakeholder group found that to achieve distribution safety enhancements while ensuring continued reliable delivery of gas at an affordable cost to customers, a high-level flexible rule should be promulgated by PHMSA requiring each operator of a gas distribution system to develop and implement a formal integrity management plan that addresses key elements outlined by the DOT Inspector General. The group also found that this rule should be implemented in conjunction with a nationwide education program on 3-digit One-Call dialing, plus continuing R & D.

First and foremost, the stakeholder group determined that the wide differences between gas distribution pipeline systems operated across the U.S. make it impractical simply to apply the integrity management requirements for gas transmission pipelines to distribution. The diversity among gas distribution pipeline operators also makes it impractical to establish prescriptive requirements that would be appropriate for all circumstances. Over half the distribution operators that will be affected by this rule are small entities – city owned utilities that serve fewer than one thousand customers and have revenues less than one million dollars per year. Thus, it is important that any rule not impose a one-size-fits-all approach. The DIMP stakeholder group found that it would be most appropriate to require that all distribution pipeline operators, regardless of size, implement an integrity management program that would contain 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 performance measures to its regulator.

These seven elements will be clarified by way of guidance being developed by a nationally recognized standards body to provide a basis for operator compliance and for regulator enforcement. The DIMP stakeholder group found that this guidance should also focus on ways of verifying the effectiveness of an operator's leak management program as an essential element of a risk-based distribution integrity management approach.

AGA and APGA are committed to working with all stakeholders with a goal of completing the distribution integrity management rule by PHMSA early next year.

The DIMP stakeholder group also found that federally mandated installation of excess flow valves on service lines to customers is not appropriate under the distribution integrity regulation. State, industry and public members of the DIMP stakeholder group submitted formal comments to PHMSA recommending that operators who choose not to voluntarily install excess flow valves in all circumstances should instead develop a process whereby the installation of these valves for specific service lines is based on defined risk criteria. The members of this stakeholder group outlined decision criteria for installation of the valves, also concluding that, depending on the situation, there may be more effective methods for controlling the risk to a service line.

AGA does not support federally mandated installation of excess flow valves; nor does such a mandate have the support of the majority of state safety regulatory agencies, many of which are satisfied that operators are installing them where they can prove to be effective. Indeed, the National Association of Utility Regulatory Commissioners (NARUC) and the National Association of Pipeline Safety Representatives (NAPSR) have passed resolutions to that effect. Many utilities already install these valves voluntarily, and the number is expected to grow.

At the same time, over the past several years, AGA has facilitated forums with industry and regulators to ensure dissemination of the most up-to-date operational information about excess flow valves. We believe that operators now have the information needed to determine if these valves would be effective for their systems. Combined with the proposed risk-based criteria, the operator’s decision on whether to install the valves would have a sound technical basis to provide such protection where it is most appropriate.

Excavation Damage – The Big Threat to Distribution Pipelines

With that, we turn again to excavation damage on natural gas distribution lines. As the distribution safety statistics have repeatedly shown, excavation damage represents the single greatest threat to distribution system safety, reliability and integrity. Although the nationwide education program on the three-digit One-Call dialing to prevent excavation damage, together with the DIMP rule, is a step in the right direction, the DIMP stakeholder group found that more is needed.

Gas pipeline facility operators are required to have damage prevention programs under current DOT regulations. However, preventing excavation damage to gas pipelines is not completely under the control of such operators. Reducing this threat requires affecting the behavior of persons not subject to the jurisdiction of pipeline safety authorities (e.g. excavators working for entities other than pipeline facility owners/operators). Pipeline facility operators currently approach this through educational efforts.

Data from the last five years has demonstrated that states, such as Minnesota, Virginia, Georgia, Connecticut and Massachusetts have experienced a substantially lower rate of excavation damage to pipeline facilities than states that do not have stringent enforcement powers and/or programs. I have brought along a chart that compares the measurable results of effective programs in Virginia and Minnesota against the results in a state where the absence of some key processes precludes an effective program (Attachment 2). The lower rate of excavation damage translates directly to a substantially lower risk of serious incidents on gas and hazardous liquid pipelines and avoided consequences resulting from excavation damage to pipelines.

The DIMP stakeholder group explored a variety of approaches to enhancing damage prevention programs. The group found that a comprehensive damage prevention program includes not only education but also effective enforcement. Currently, the U.S. Department of Justice is responsible for enforcing federal infrastructure damage prevention statutes on parties conducting excavations. However, and most unfortunately, the Department has rarely exercised such authority.

Programs such as Virginia's show that nine key elements must be present and functioning for the damage prevention program to be effective. The DIMP group concluded that federal legislation would be necessary to encourage such programs in all states. This should include providing additional funding for the states, apart from funding already being provided under the matching grants or One-Call programs.

As quoted from the above-mentioned DIMP report, the nine elements a state program should have are as follows:

(1) Effective communication between operators and excavators -- Provide for appropriate participation by operators, excavators, and other stakeholders in the

development and implementation of methods for establishing and maintaining effective communications between stakeholders from receipt of an excavation notification until successful completion of the excavation, as appropriate.

(2) Fostering support and partnership of stakeholders -- Have a process for fostering and ensuring the support and partnership of stakeholders including excavators, operators, locators, designers, and local government in all phases of the program.

(3) Operator's use of performance measures – Include a process for reviewing the adequacy of a pipeline operator's internal performance measures regarding persons performing locating services and quality assurance programs.

(4) Partnership in employee training – Provide for appropriate participation by operators, excavators, and other stakeholders in the development and implementation of effective employee training programs. This would ensure that operators, the one-call center, the enforcing agency and the excavators have partnered to design and implement training for employees of operators, excavators and locators.

(5) Partnership in public education – Have a process for fostering and ensuring active participation by all stakeholders in public education for damage prevention activities.

(6) Dispute resolution process – Feature a process for resolving disputes that defines the state authority's role as a partner and facilitator to resolve issues.

(7) Fair and consistent enforcement of the law -- Provide for the enforcement of its damage prevention laws and regulations for all aspects of the excavation process including public education. The enforcement program must include the use of civil penalties for violations found by the appropriate state authority.

(8) Use of technology to improve all parts of the process – Include a process for fostering and promoting the use, by all appropriate stakeholders, of improving technologies that may enhance communications, locate capability, and performance tracking.

(9) Analysis of data to continually evaluate/improve program effectiveness – Contain a process for review and analysis of the effectiveness of each program element, and for implementing improvements identified by such program reviews.

AGA and APGA recommend that Congress enact legislation that modifies Title 49 USC Subtitle VIII, Chapter 601, *§ 60105 - State pipeline safety program certifications*, to insert a new section outlining the nine elements and providing for additional funding for implementation of the program. Such funding should be allocated directly to the State agency having oversight over pipeline safety. In addition to our own members as excavators, a variety of stakeholders will be affected by the proposed legislation, including in most states, entities presently not under the jurisdiction of state pipeline safety authorities. Accordingly, funding authority for the program should be sought from general revenues.

Past experience has shown that, without legislation, PHMSA's activities under its existing authority have had a limited effect, principally because many of the entities causing excavation damage were outside the agency's jurisdiction. Moreover, without associated funding, a legislative mandate for an enhanced program -- be it at the federal level or at the state level -- would be equivalent to an unfunded mandate and have minimal effect on existing state programs.

Finally, AGA and APGA support providing continued funding authority for grants to states to support One-Call programs and for partial funding of the Common Ground Alliance (CGA) damage prevention organization. The CGA has been instrumental in bringing to the forefront the need for excavation damage prevention as a shared responsibility among all locators, One-Call system operators, excavators and owners or operators of buried infrastructure facilities. Development and adoption of consensus-based best practices, education, and damage data collection are significant and worthwhile efforts under CGA sponsorship and should be continued.

The statistics are clear. Excavation damage prevention presents the single greatest opportunity for distribution safety enhancements.

Gas Transmission Integrity Reassessment Time Interval

The Interstate Natural Gas Association of America testimony today addresses the 7-year reassessment interval required by the gas transmission integrity rule. In particular, gas company planning personnel view the overlap between the baseline assessments and the reassessments that must take place for a pipeline segment in year 7 after the baseline assessment as representing an unwarranted increase in workload and demand for services, with possible gas supply interruptions. This will affect interstate as well as intrastate transmission systems. AGA and APGA believe that a pipeline segment's reassessment interval should be based on technical arguments. It is our hope that in evaluating the appropriateness of the 7-year requirement, the U.S. Government Accountability Office (GAO) will seek to uncover all of the facts and that, based on the GAO report, Congress would then consider options for allowing a change to the interval that would be consistent with GAO findings. This will allow operators to continue to deliver natural gas safely and affordably.

Summary

The natural gas utility industry is proud of its safety record. Natural gas has become the recognized fuel of choice by citizens, businesses and the federal government.

Public safety is the top priority of natural gas utilities. We invite you to visit our facilities and observe for yourselves our employees' dedication to safety. We are committed to continuing our efforts to operate safe and reliable systems and to strengthening One-Call laws and systems in every state.

AGA and APGA believe that Congressional passage of pipeline safety reauthorization this year will result in timely and significant distribution system safety improvements. Further, because of the wide variety of distribution systems across the U.S, promulgation of a distribution integrity regulation by PHMSA may yield effective enhancements in distribution safety if PHMSA allows gas utilities risk-based options to address threats to pipeline integrity in their specific systems and situations.

Despite the fact that our members, when undertaking excavation themselves, would have to also abide by the provisions of an enhanced state damage prevention program, the members of AGA and APGA emphatically endorse the recommendation that Congress enact legislation that incentivizes states to adopt stronger damage prevention programs. By doing so, all states could realize a significant, marked reduction in incidents on distribution lines.

Thank you for providing the opportunity to present our views on the important matter of pipeline safety. To reiterate, since the passage of the 2002 Pipeline Safety Act, PHMSA and the industry have made significant progress – and now we urge you to go a step further in that positive direction by addressing excavation damage. We feel confident overall in reporting today that, other than this issue, the pipeline safety program is going well.

Attachments:

1) Comparison of Incidents
2) States With Strong Prevention Programs
3) The Nine Elements of an Effective Excavation Damage Program
4) Path To Success