TESTIMONY OF
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ON BEHALF OF
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

BEFORE THE
SUBCOMMITTEE ON SURFACE TRANSPORTATION AND
MERCHANT MARINE INFRASTRUCTURE, SAFETY AND SECURITY
COMMITTEE ON COMMERCE, SCIENCE AND TRANSPORTATION
UNITED STATES SENATE

HEARING ENTITLED
"ENSURING THE SAFETY OF OUR NATION'S PIPELINES"

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Mr. Chairman and Members of the Subcommittee:

Good afternoon. My name is Gary Sypolt, and I am CEO of Dominion Energy. Dominion Energy is the natural gas-related business unit of Dominion Resources. Dominion Resources is one of the nation's largest producers and transporters of energy, with a portfolio of more than 27,500 megawatts of generation, 12,000 miles of natural gas transmission, gathering and storage pipeline and 6,000 miles of electric transmission lines. Dominion operates the nation's largest natural gas storage system with 942 billion cubic feet of storage capacity, and owns and operates the Cove Point liquefied natural gas facility in Maryland. We also serve retail energy customers in 12 states. Our corporate headquarters are in Richmond, Virginia.

I am testifying today on behalf of the Interstate Natural Gas Association of America (INGAA). INGAA represents the interstate and interprovincial natural gas pipeline industry in North America. INGAA's members transport the vast majority of the natural gas consumed in the United States through a network of approximately 220,000 miles of transmission pipeline. These transmission pipelines are analogous to the interstate highway system; in other words, these are large capacity transportation systems spanning multiple states or regions.

Natural Gas

While natural gas has been an important part of the United States energy supply portfolio for many years, the recent focus on energy security and controlling emissions of greenhouse gases is making natural gas even more important to America's energy future. Natural gas currently provides about 25 percent of the total energy utilized in the nation. This includes fueling the generation of about 20 percent of our electricity and heating the bulk of our homes and businesses. The clean-burning properties of natural gas make it an attractive resource for the future as the U.S. looks for ways to reduce carbon and other emissions. Many experts have advocated natural gas as a logical "partner" for renewable power resources, with natural gas providing reliable electricity when conditions do not permit the operation of solar and/or wind generation. In addition, natural gas remains a largely domestic energy resource. The U.S. produces approximately 85 percent of the natural gas consumed domestically; most of the remaining natural gas supplies are imported from Canada. Only about 2 percent of our natural gas supply is imported from outside of North America. There is little doubt that natural gas can fulfill its potential as a long-term contributor to the U.S. energy future. Natural gas supplies have grown dramatically in just the last 5 years, and it is estimated that the U.S. natural gas resource base can supply us for more than 100 years at current consumption levels.

Regulatory Structure of the Interstate Natural Gas Transmission System

Mr. Chairman, I am going to limit my comments to the segment of the natural gas delivery system represented by INGAA – the interstate natural gas transmission system. As I mentioned, interstate natural gas transmission pipelines can be compared to the interstate highway system and as such, cross state boundaries and have a significant impact on interstate commerce. Congress recognized the inherently interstate nature of this commerce by enacting the Natural Gas Act to provide for federal economic regulation of interstate pipelines in 1938 and, shortly thereafter, expanded this federal role to include siting authority for such pipelines. This law now is administered by the Federal Energy Regulatory Commission (FERC).

With regard to pipeline safety, Congress enacted the Natural Gas Pipeline Safety Act in 1968. This law (as amended) provides for the exclusive regulation of interstate natural gas and hazardous liquid pipelines by the Office of Pipeline Safety (OPS) located in the Pipeline and Hazardous Materials Safety Administration (PHMSA). The authority to regulate intrastate pipelines is largely delegated to state pipeline safety agencies.

It is worth noting that with regard to the nation's interstate natural gas pipelines, the regulation of economic matters and the regulation of safety matters have always been handled by two separate entities. The exclusive safety focus of PHMSA has been an advantage of the agency. Over the years, some have suggested an expansion of PHMSA's authority beyond safety matters. Given the importance of the mission, and the fact that PHMSA has a relatively small staff, we are concerned about any movement away from safety. INGAA urges Congress and the Administration to maintain that exclusive safety focus for PHMSA.

Following enactment of the Natural Gas Pipeline Safety Act, OPS adopted pipeline safety regulations (in 1970) for natural gas transmission pipelines based on engineering consensus standards developed by the American Society of Mechanical Engineers. These engineering consensus standards first were adopted by the industry in 1953 and had been continually updated over the following decades. OPS established performance measures (e.g., pipeline accident reports, company activity records and engineering documentation) and initiated a formal inspection and enforcement program for interstate natural gas transmission pipeline systems. Conversely, natural gas intrastate or distribution piping safety guidelines were implemented under similar pipeline safety regulations and were delegated to the state pipeline safety agencies. Hazardous liquid pipelines were incorporated into the OPS regulatory structure in 1984.

The pipeline safety processes of INGAA member companies and the applicable regulations for natural gas transmission pipelines have evolved and become more refined over the last 40 years as new technology has became available, new physical properties have been identified through engineering and scientific analysis, and societal expectations have changed. These substantive changes in processes and regulations have been accomplished through:

- Continuing research,
- Improved practices and processes,
- Revised engineering consensus standards,
- New regulatory initiatives,
- Focused Congressional actions, and
- Improved education and training.

Natural Gas Transmission Pipelines are the Safest Mode of Energy Transportation

While natural gas transmission pipeline operators will not be satisfied without continuous safety improvement, the safety record of our industry compares very well to other modes of transportation and energy delivery. One way to measure safety performance is to identify the number of accidents involving a fatality or injury. These are classified as "serious" incidents by OPS. Because natural gas pipelines are buried and typically are in isolated locations, pipeline accidents involving fatalities and injuries are very rare.

For example, the chart below (from OPS) sets forth safety statistics for natural gas transmission pipelines since the last Pipeline Safety Act reauthorization. This chart first depicts the categories of fatalities and injuries. It also categorizes property damage based on whether it is damage to public property or damage to the pipeline operator’s property and the amount of natural gas lost to the atmosphere during both the accident and the subsequent repair of the pipeline.

National Gas Transmission Onshore: Consequences Summary Statistics: 2005-2009

Year	Public Fatalities		Industry Fatalities		Public Injuries		Industry Injuries		Total Property Damage (C) (D)	Damage to Public Property (E) (C)		Damage to Industry Property (F) (C)		Value of Product Lost (C)	
2005	0	0%	0	0%	2	40%	3	60%	$214,506,403	$98,072,639	45%	$105,375,752	49%	$11,058,012	5%
2006	1	33%	2	66%	1	33%	2	66%	$31,020,029	$2,869,452	9%	$20,882,094	67%	$7,268,481	23%
2007	1	50%	1	50%	1	14%	6	85%	$44,562,382	$1,630,991	3%	$24,096,641	54%	$18,834,750	42%
2008	0	0%	0	0%	2	40%	3	60%	$111,608,494	$6,643,699	6%	$98,424,350	88%	$6,540,445	5%
2009	0	0%	0	0%	7	63%	4	36%	$31,789,417	$2,005,498	6%	$25,216,056	79%	$4,567,863	14%
Totals	2	40%	3	60%	13	41%	18	58%	$433,486,727	$111,222,281	25%	$273,994,894	63%	$48,269,552	11%

From 2005 to 2009[1], there have been two public fatalities due to natural gas transmission line accidents. One in 2006 involved a bystander near an incident caused by excavation damage to the pipeline, and the other in 2007 involved a driver in an automobile near a pipeline incident caused by corrosion. The three non-public natural gas transmission pipeline fatalities since 2005 were a third-party excavator, a pipeline employee and a contractor working for a pipeline company.

During this same period, 2005 to 2009, there were 13 injuries to the public. Four of these occurred when citizens were in vehicles that struck and damaged pipeline facilities. There were also five injuries to third-party excavators and 13 injuries to either pipeline employees or contractors working for the pipeline company.

As you can see from the chart, on the average, natural gas transmission pipeline incidents do not greatly affect public property. The exception in 2005 primarily was attributable to $85 million of damage to a power plant adjacent to a pipeline accident. The large amount

[1] Additional information is available in individual pipeline incident reports http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=fdd2dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print

of industry property damage in 2005 was related to the Katrina/Rita hurricane damage in the Gulf Coast region and the large number in 2008 was largely due to a tornado destroying a pipeline compressor station ($85 million).

Progress Since the Last Reauthorization

Pipeline Integrity Program

Section 14 of the Pipeline Safety Improvement Act of 2002 (PSIA) mandated an integrity management program for natural gas transmission pipelines. Specifically, the PSIA requires operators of natural gas transmission pipelines to: (1) identify all the segments of their pipelines located in areas where the pipeline is adjacent to significant population density, known as high consequence areas (HCAs); (2) develop an integrity management program (IMP) to reduce the risks to the public in these HCAs; (3) undertake structured baseline integrity assessments (inspections) of all pipeline segments located in HCAs, to be completed within 10 years of enactment; (4) develop a process for repairing any anomalies[2] found as a result of these inspections; and (5) reassess these segments of pipeline every seven years thereafter in order to verify continued pipe integrity.

The PSIA requires that these integrity inspections be performed using one of four methods: (1) an inline inspection device, alternatively called a smart pig; (2) hydrostatic pressure testing (filling the pipe up with water and pressurizing it well above operating pressures to verify a safety margin); (3) direct assessment (digging up and visually inspecting sections of pipe); or (4) "other alternative methods that the Secretary of Transportation determines would provide an equal or greater level of safety."

Following such inspections, a pipeline operator is required by the PHMSA regulations implementing the PSIA to repair all non-innocuous anomalies and adjust operation and maintenance practices (i.e. apply additional corrosion protection measures in active corrosion areas to prevent further corrosion growth) to minimize the probability of "serious incidents"[3].

Baseline IMP assessments – the type of work in which our industry now is engaged – are an effective means of identifying any material or original construction defects that were not discovered when a pipeline was built as well as active corrosion problems. Corrosion is an on-going, time-based phenomenon that is managed and controlled using integrated technologies and processes (e.g., cathodic protection, pipe coatings). Internal inspection devices are the predominant means for performing integrity assessments of natural gas transmission pipelines, because these are the most versatile and efficient devices for this inspection process. The other assessment alternatives prescribed by statute are useful when smart pig technology cannot be effectively used. A drawback associated with these other alternatives is that they require a pipeline to cease or significantly curtail natural gas

[2] An anomaly is defined as a precursor to a possible reportable incident in the future.
[3] "The rule will ***significantly reduce the likelihood*** of pipeline accidents that result in ***deaths*** and ***serious injuries***."; Page 69800, Federal Register / Vol. 68, No. 240 / December 15, 2003.

delivery operations for significant periods of time (e.g., hydrostatic pressure test) or else require extensive excavation of the pipeline during every assessment (e.g., direct assessment).

Periodic risk-based reassessments are an effective method for identifying whether corrosion prevention systems are adequately preventing this “time-dependent” deterioration. While material and original construction defects are not common, they are for practical purposes eliminated for the remaining life of the pipeline once they are identified during a smart pig assessment (or the post-construction hydrostatic test) and repaired. Recently designed smart pigs can also effectively identify small dents in the pipeline. These dents may or may not be precursors for a corrosion failure, depending upon whether the pipe has been gouged. Sorting through these dents to identify actual corrosion precursors is a current focus using these updated smart pig devices.

Based on data from over three quarters of the IMP inspection baseline period (2002 – 2009), there is ample basis for concluding that the integrity of our pipelines is being maintained and that such pipelines are becoming safer as a result of eliminating the precursors to possible future accidents. It also is clear that the industry is dutifully implementing the IMP program prescribed by Congress, since all INGAA member companies have been subject to in-depth IMP audits by PHMSA to assure that the programs are comprehensive and implemented consistently according to Congressional mandates and PHMSA requirements.

PHMSA has received the reports on IMP progress achieved through the end of 2009 and the data is presented on the following tables. The first table depicts the transmission pipelines that have been subject to an assessment for the first time under the IMP program (baseline). Let me highlight a particular performance measure. The “Immediate” category includes small isolated anomalies (e.g., corrosion, pipe dent with a gouge) that should be repaired quickly, since these situations might lead to a leak or pipe rupture within a short period of time. The “Scheduled” category addresses individual anomalies (e.g., corrosion) that should be repaired or reassessed before they grow to the “Immediate” category. The bottom row depicts the rate (per mile) of finding either “Immediate” or “Scheduled” category anomalies after decades of operation (e.g., 10-50 years).

Baseline IMP Data for Gas Transmission Pipeline Integrity Program	Natural Gas Onshore Transmission Miles within U.S.	Transmission Pipeline Miles Assessed per Year coincidently with the IMP program	Total Number of Miles of Pipelines within HCAs	Miles of Pipe Assessed within HCAs per Year	Number of Immediate Category Anomalies (failure precursors) within an HCA	Number of Scheduled Category of Anomalies within an HCA
2004	298,207	31,273	21,764	3,997	104	599
2005	297,968	19,516	20,561	2,908	261	378
2006	293,696	20,250	19,949	3,500	169	342
2007	291,898	25,940	19,277	4,661	258	452
2008	295,779	20,258	19,568	2,454	146	217
2009 (preliminary)	283,975	22,015	18,663	2,269	124	251
Cumulative Baseline Inspection Results		139,252		19,789	1,062	2,239
Rate of Anomalies found (dents & corrosion) in the Baseline Assessment (per Mile)					*.054*	*.113*

As these "Immediate" and "Scheduled" time-dependent precursors (e.g., anomalies that could possibly grow in size) are remediated and rendered benign, we expect that the rate of "Immediate" and "Scheduled" anomalies will decrease with subsequent assessments. This is because the gestation period of these corrosion anomalies to grow (if corrosion is active) to failure is significantly longer than either the present prescriptive seven-year reassessment requirement or the risk-based reassessment intervals recommended by GAO and consensus standards organizations (see later discussion).

Since the inception of the IMP program in 2002 through 2009, there have been ***no reported significant incidents*** caused by corrosion to pipelines within the HCAs that have been assessed.

The next table depicts the results of reassessments that are occurring concurrently on natural gas transmission pipelines that had been previously assessed under the IMP baseline program. As with the baseline assessment, "Immediate" and "Scheduled" precursors are identified, assessed to determine if they have changed and then remediated. As shown in the fourth row, the rate of occurrence of these corrosion anomalies and dents is significantly reduced from the baseline assessment.

Reassessment Data for Gas Transmission Pipeline Integrity Program	Miles of Pipe Re-Assessed within an HCAs per Year	Immediate Categories of Anomalies (failure precursors) within an HCA	Scheduled Categories of Anomalies within an HCA
2008	348	9	4
2009 (preliminary)	903	20	16
Cumulative Reassessment Inspection Results	1285	29	20
Rate of Anomalies (dents & corrosion) found in the Reassessment (per Mile)		*.023*	*.016*
Rate of Corrosion Anomalies (only) found in the Reassessment (per Mile)		*.003*	*.011*

In addition, the last row[4] depicts the low rate of corrosion anomalies found on the reassessments, the main focus of the IMP program. It is worth emphasizing that other data obtained from pipeline operators who have completed multiple integrity assessments over a number of years, and reviewed by GAO, strongly suggests a dramatic decrease in the occurrence of time-dependent precursors requiring repairs in subsequent assessments. This is due to corrective action being implemented based on prior integrity assessments. Also, technical analysis[5] undertaken in 2005 by the Pipeline Research Council International (PRCI), an international consensus research group, demonstrated a significant reduction in the number of serious anomalies found during risk-based reassessments (as compared to baseline assessments), suggesting that risk-based assessments using smart pig technology are extremely effective in identifying potential problems before they manifest themselves into safety problems.

Pipeline Controller Regulation

In 2001, the National Transportation Safety Board (NTSB) issued a report concerning fatigue among hazardous liquid pipeline controllers. In response, OPS undertook an effort from 2002 to 2008 to investigate pipeline control operator fatigue and identify possible solutions. While the NTSB report did not focus on natural gas transmission pipeline control room operators, INGAA participated extensively in this study effort. OPS issued a Notice of Proposed Rulemaking on this matter in September 2008. During the rulemaking, INGAA proactively worked with other pipeline trade associations to recommend changes to the proposal that would reflect the difference of practices and risks between hazardous liquid, natural gas transmission and natural gas distribution control operations. Since the rule was finalized in December 2009, INGAA member companies, working in collaboration with the Southern Gas Association, have developed an implementation manual for natural gas transmission and distribution operators. This implementation manual has been reviewed by OPS and NTSB. In February 2010, the NTSB announced that it was satisfied that its recommendation on control room personnel fatigue had been addressed by these actions. As a result, control room operator fatigue was removed from the NTSB list of “Most Wanted” safety improvements.

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[4] IMP data collected by OPS, enhanced by detailed interviews with INGAA respondents

[5] *Integrity Management Reinspection Intervals Evaluation,* Pipeline Research Council International, Inc., December 2005

Improved Incident Data and Transparency

In 2007, INGAA requested that OPS reassess the reporting criteria for reportable incidents and suggested that incident forms be amended to facilitate better data analysis of the causes and consequences of these incidents. For example, the value of natural gas lost from an incident is included in total property damage numbers. As natural gas prices increased dramatically over the last 10 years, this metric caused an increase in reportable incidents since property damage above a fixed threshold is one trigger for reporting an incident. INGAA asserted that incident data should not be artificially impacted by natural gas commodity prices. OPS undertook an effort to modify its data requirements and the result is an accident reporting form that more accurately depicts the severity of incidents. We believe this data will assist the industry, OPS and concerned public assessing the risk of natural gas transmission pipelines and determining whether modified practices and procedures are reducing the occurrence of pipeline accidents.

Allowing Increased Operating Pressure in Specific Transmission Pipelines

In 2006, several INGAA member companies requested that OPS consider allowing newer pipelines with improved technologies to operate a higher operating pressure. The "safety factors" for natural gas pipelines were established in the 1950s and OPS adopted those safety factors in the original pipeline safety regulations promulgated in the 1970s. Since then, pipeline technologies and processes have advanced tremendously (e.g., materials, IMP, smart pigs). The operating pressure proposed by the pipelines already was part of international engineering consensus standards, and Canada has utilized these refined criteria since the 1980s. The United Kingdom adopted these criteria for their existing pipeline infrastructure in the 1990s after it determined that this change would result in no effective reduction in the safety. The U.K. also concluded that these updated criteria would enable more efficient use of the country's existing infrastructure and thereby obviate the need to construct additional pipeline capacity (along with all of the disruption that would cause in such a densely populated country). Utilizing extensive prior research and international experience, OPS issued several special permits to allow higher operating pressures than previously allowed under regulations and to assess the benefits of additional design, construction, operating and maintenance requirements imposed as a condition for such permits. This exploratory work has resulted in a new regulation that will allow higher operating pressure on new pipelines that meet much stricter criteria for design, construction, operation and maintenance.

Improved Material and Construction Practices for Natural Gas Transmission Pipelines

The natural gas transmission pipeline infrastructure in the U.S. has expanded significantly in the last decade to meet increased demand for natural gas and to connect new natural gas supply basins to consuming markets. This surge in new pipeline construction required many new material sources, especially steel pipe. At the same time, OPS adopted more stringent material, construction and inspection regulatory requirements for projects approved with special permits (allowing increased operating pressure in specific transmission pipelines) that exceeded those for comparable pipelines in other nations. The conjunction of these two events resulted in the unacceptable performance of a sample of steel pipe in a particular pipeline project during pre-service integrity testing. INGAA, in cooperation with OPS, embarked on an unprecedented effort to identify the phenomenon that caused these pre-service pipe quality issues and to implement processes and procedures to minimize the occurrence of these events in the future. All pipelines wishing to operate at higher pressures (under these new regulatory requirements) have quickly adopted these practices and procedures. This cooperative process resulted in significantly faster implementation of solutions than would have occurred under the traditional engineering consensus standards process or a rulemaking by the agency.

Concurrently, INGAA has focused on identifying ways to improve the process for constructing new natural gas transmission pipelines. This requires a reassessment of the traditional Quality Assurance and Quality Control (QA/QC) processes and practices in light of changes in materials, technology, the expectations of industry and regulators. The same implementation model used in the pipe quality effort is being utilized to affect change quickly in the construction process.

Incorporation of Safety Culture

INGAA member companies are exploring new avenues for improving employee and public safety performance. While important, there are limits on the ability to achieve improvements based solely on traditional techniques such as training, qualification and increased inspection. Pipeline workers – whether pipeline employees, contractors or excavators – must be motivated to make safety a primary focus. There must be a safety culture. Safety culture has been described as an inherent attitude towards safety of an individual, whether they are supervised or not supervised. Our goal is to create and improve this safety culture.

The U.S. Chemical Safety Board has advocated safety culture as a constructive means to improve safety performance, and INGAA has embraced this philosophy. The natural gas transmission pipeline industry has had an excellent employee safety record over the decades and we have extended that focus and thought process to encompass work practices as they impact public safety. We are now in the third year of implementing this process and have invited our contractor community (members of the INGAA Foundation, which is affiliated with INGAA) to adopt the philosophy as well.

Recommendations to Improve the Pipeline Safety Act

The regulatory and process changes referenced in this testimony all point to a pipeline safety regime that is working well to minimize risk to the public. INGAA believes that the existing pipeline safety program has been a success, especially with respect to natural gas transmission efforts. For this reason, we would endorse a simple reauthorization bill that reauthorizes the pipeline safety program for four years without any new regulatory programs or mandates. Given the success of the program over the last four years, the expiration of the current authorization in September, and the short time remaining in this Congress, a simple reauthorization bill is a logical solution. Still, should Congress choose to move beyond a simple reauthorization bill, we would offer the following suggestions, which build on existing efforts under the law:

Removal of Exclusions from Participating in Excavation Damage Prevention Program

The "serious" incident data cited earlier in my testimony points to the importance of damage prevention as an essential means to avoid fatalities and injuries. The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act) took an important step forward by creating incentives for states to adopt improved damage prevention programs that meet nine critical elements identified in the Act. This was an important step in raising the performance bar across the states.

One of the larger issues still existing in some of the State excavation damage prevention programs is the categorical exclusion of certain excavators from the notification requirements of state "one-call" systems. These excluded groups often include entities such as state highway departments (and their contractors), municipal governments and railroads, who together represent a significant percentage of excavation activity each year. In order to provide the public with maximum protection, exemptions from state one-call programs should be strongly discouraged. We recommend that such one-call exemptions be a factor that PHMSA must consider when deciding whether to make annual state pipeline safety grants and one-call grants.

The importance of damage prevention was highlighted in two recent pipeline accidents in Texas. On June 7th, an intrastate natural gas pipeline near Dallas was struck by utility workers building a power line, causing one fatality and eight injuries. The next day, another intrastate natural gas pipeline in the Texas Panhandle was struck by a bulldozer engaged in construction work, causing two fatalities and one injury. The Texas Railroad Commission (which regulates these pipelines) and the National Transportation Safety Board are investigating these accidents, so the precise causes remain unknown. However, it is clear that some sort of miscommunication occurred between the excavators and the pipeline operators. Effective communication is the key, but the fact that these preventable accidents are still happening means that more remains to be done. An effective damage prevention effort is about more than just making the first call; it also means full participation by all excavators and underground utility operators, accurate and timely marking of underground utilities when a call is made, and using due caution when excavating around marked underground utilities. Every state program should actively be moving towards these goals.

Risk-Based Interval for Reassessments in the Integrity Management Program

During the last reauthorization, INGAA petitioned Congress to remove the statutory requirement for mandatory reassessments every seven years for natural gas transmission pipeline in HCAs. We have previously provided Congress with the rationale supporting this amendment, along with detailed technical support and evidence of the concurrence by many groups including OPS, GAO, international pipeline safety experts and the American Society of Mechanical Engineers (ASME).

As part of the PIPES Act, Congress directed OPS to present a recommendation on whether to amend the law governing reassessment intervals on natural gas transmission pipelines. Deputy Secretary of Transportation Adm. Thomas Barrett outlined the numerous reasons why the seven-year requirement should be rescinded in a memo to Congress dated November 27, 2007. The GAO developed a report[6] on this issue as well, stating in 2006:

To better align reassessments with safety risks, the Congress should consider amending section 14 of the Pipeline Safety Improvement Act of 2002 to permit pipeline operators to reassess their gas transmission pipeline segments at intervals based on technical data, risk factors, and engineering analyses. Such a revision would allow PHMSA to establish maximum reassessment intervals, and to require short reassessment intervals as conditions warrant.

Since then, OPS and the industry have gathered additional documentation, data and experience that validate the previous request. We believe a clear statutory mandate from Congress authorizing the adoption of risk-based intervals would not reduce safety performance, but would enhance safety through a more efficient and effective allocation of industry and PHMSA resources.

Review of Legacy PHMSA Regulatory Requirements in Light of New Technology and Processes

One of the benefits of the IMP was the improvement of pipeline management practices due to new technology and processes. Much of the justification of the cost effectiveness of the new IMP regulatory program was that legacy pipeline safety requirements, such as class location upgrades, would be superseded by new, more sophisticated regulations and practices. While the industry has adopted the new, more sophisticated practices and has documented them in consensus standards, redundant legacy OPS regulations, such as mandatory class location upgrades, remain in place. This causes an unnecessary overlap in procedures to achieve the same safety goals.

INGAA would request that Congress charge PHMSA and consensus standards organizations such as the ASME with examining whether parts of the present compendium of pipeline safety regulations have become redundant in light of changes in technology and processes adopted by more recent regulations. If the record supports a conclusion that such legacy requirements are redundant and unnecessary, we ask that such regulations be rescinded in favor of the new (and more effective) integrity management requirements.

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[6] GAO-06-945, *Natural Gas Pipeline Safety: Risk-Based Standards Should Allow Operators to Better Tailor Reassessments to Pipeline Threats,* September 2006.

Conclusion

Mr. Chairman, this Subcommittee and the Congress can take pride in the fact that the pipeline safety efforts embarked upon by you and your colleagues have improved public safety significantly in the last decade. An energy delivery system that was, by all measures, already the safest in the nation, has continued to define new boundaries for developing a safety culture and reducing risk to the public. Given the importance of natural gas in America's energy future, the construction and operation of a safe transportation system for natural gas is critical. INGAA and its members will not be satisfied without continuous safety improvement, but we have worked hard in implementing the Congressional goals articulated in the PIPES Act and in the PSIA. The safety performance metrics collected by PHMSA from the member companies of INGAA demonstrate this commitment. This is an effective safety program, and we hope you agree that any changes should build on existing programs and successes.

Thank you for holding this hearing and for inviting me to participate on behalf of INGAA. Please let us know if you have any additional questions, or need additional information.