TESTIMONY OF
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BEFORE THE
SUBCOMMITTEE ON ENERGY AND ENVIRONMENT
COMMITTEE ON ENERGY AND COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES

HEARING ENTITLED
PIPELINE SAFETY OVERSIGHT AND LEGISLATION

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Mr. Chairman and Members of the Subcommittee:

Good afternoon. My name is Donald Santa, and I am president 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 interstate 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.

Before I proceed with my testimony, I want to say a few words about the San Bruno accident. We express our sincere condolences to those who lost family members and friends, who were injured, or who had their homes damaged or destroyed in the tragedy in San Bruno. While PG&E is not an INGAA member, nor was the San Bruno pipeline an interstate pipeline, the events in California several days ago underscore the need for and importance of continued high levels of pipeline safety practices across the entire natural gas industry. Because the cause of the accident is not yet known, we think it is important not to jump to any conclusions about what specifically must be done going forward. Once the facts from the accident investigation are known, we commit to working with policymakers on developing effective, well-founded solutions that will improve the overall safety performance of the industry.

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 greenhouse gas emissions 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 generators that produce 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 two 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 five 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 for Interstate Natural Gas Transmission Pipelines

Mr. Chairman, I will 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 within the Pipeline and Hazardous Materials Safety Administration (PHMSA). The authority to regulate intrastate pipelines, such as the PG&E line in San Bruno, is largely delegated to state pipeline safety agencies.

Following enactment of the Natural Gas Pipeline Safety Act, OPS adopted pipeline safety regulations 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. The initial pipeline safety regulations included requirements for design, construction, operation, inspection and maintenance of natural gas transmission pipelines. This included imposing more stringent requirements for each facet of pipeline safety regulation in highly populated areas. 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. Safety guidelines for natural gas intrastate and distribution pipelines were issued 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 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.[1] 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.

[1] See information at www.bts.gov.

For example, the table below (from OPS) sets forth safety statistics for natural gas transmission pipelines during the five-year span that includes the period since the last Pipeline Safety Act reauthorization. This table 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[2], 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 injuries were suffered by citizens in vehicles that struck and damaged pipeline facilities. There also were 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 table, 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 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).

The table above does not include information for 2010. We are aware of two excavation damage-related accidents in Texas this summer that caused three fatalities, plus the accident in San Bruno, California which caused at least four fatalities.

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[2] 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

Progress Since the Last Reauthorization

Pipeline Integrity Program

Section 14 of the Pipeline Safety Improvement Act of 2002 (PSIA) mandated a standardized integrity management program (IMP) for natural gas transmission pipelines located in populated areas. The focus on populated areas is important. Existing pipeline safety regulations covered a full range of matters – from design, to construction and materials, to operations, inspections and maintenance. These regulations applied to <u>all</u> natural gas transmission pipelines. Congress in the PSIA went one step further to create an additional layer of regulation focused on enhancing safety in populated areas.

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 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 actionable anomalies[3] found as a result of these inspections; and (5) reassess these segments of pipeline every 7 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 (commonly referred to as 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"[4].

Baseline IMP assessments – the type of work in which our industry now is engaged – are an effective means of identifying active corrosion problems as well as any material or original construction defects that were not discovered when a pipeline was built. 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 most versatile and efficient means for assessing the condition of natural gas transmission pipelines and, therefore, this method is preferred by most operators. The other assessment alternatives authorized by statute are useful when smart pig technology cannot be used. A drawback associated with these alternatives is that they require a pipeline to cease or curtail natural gas delivery operations for significant periods (e.g., hydrostatic pressure test) or else require extensive excavation of the pipeline during every assessment (e.g., direct assessment).

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[3] An actionable anomaly is defined as a precursor to a possible reportable incident in the future.
[4] "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.

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 uncommon, they are for practical purposes eliminated for the remaining life of the pipeline once they are identified during a smart pig assessment (or a post-construction hydrostatic test) and repaired. Newer smart pigs also can 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 now is a focus using these newer smart pig devices.

Now that we are over three quarters of the way through the IMP inspection baseline period (2002 – 2009), the data amply supports the conclusion 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. All INGAA member companies have been subject to in-depth IMP audits by PHMSA to assure that the programs are comprehensive and implemented consistent with Congressional mandates and PHMSA requirements.

As presented in the following tables, PHMSA has posted data on IMP results achieved through the end of 2009. The first table depicts the transmission pipelines that have been subject to an assessment under the IMP program (baseline). Let me highlight a particular performance measure. The "immediate" category includes 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. The "scheduled" category addresses individual anomalies (e.g., corrosion) that should be repaired or reassessed before they grow to a level that would place them in the "immediate" category. The bottom row of this table presents 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	292,887	23,092	19,103	2,343	124	251
Cumulative Baseline Inspection Results		140,329		19,864	1,062	2,239
Rate of Anomalies found (dents & corrosion) in the Baseline Assessment (per Mile)					*.053*	*.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 for these corrosion anomalies to grow (if corrosion is active) to the point at which they may pose an imminent risk of leak or rupture is significantly longer than the seven-year reassessment requirement mandated by the PSIA.

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 on natural gas transmission pipelines that had received a baseline assessment during the first years of the IMP. As with the baseline assessment, "immediate" and "scheduled" precursors first are identified, then are assessed to determine if anything has changed since the last test, and finally are remediated. As shown in the fourth row of this table, the rate of occurrence of corrosion anomalies and dents is significantly reduced from the rate observed during the baseline assessment. The last row of the table [5] presents the rate of corrosion anomalies (only) found during the reassessments.

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*

This data is evidence that the IMP is achieving its primary purpose because it is reducing possible corrosion precursors. It is worth emphasizing that other data obtained from pipeline operators that 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 as a result of prior integrity assessments. Also, technical analysis[6] 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 as safety problems.

Much has been made recently of the fact that IMP focuses on only about seven percent of total natural gas transmission pipeline mileage. First, this is fully consistent with the intent of

[5] IMP data collected by OPS, enhanced by detailed interviews with INGAA respondents
[6] *Integrity Management Reinspection Intervals Evaluation*, Pipeline Research Council International, Inc., December 2005

Congress in the PSIA to focus on areas where natural gas transmission pipelines are located adjacent to significant population density (i.e., HCAs). The vast majority of natural gas transmission pipeline mileage is located in less densely populated areas. Second, as a practical matter, a significantly greater total mileage of natural gas transmission pipelines is receiving integrity inspections and repairs as a result of the IMP. This is because pipeline operators are completing these inspections predominately using smart pigs. Pigs must be "launched" and "received" at aboveground facilities such as compression stations, which typically are located 75 to 100 miles apart. While a pipeline segment between a compression stations may contain only a few miles of scattered HCAs, the entire 75-to-100 mile segment must be inspected in order to capture those few HCA miles. The level of this "overtesting" that has occurred as a result of IMP is illustrated in the first of the preceding two tables. In 2009, for example, about 23,000 miles of pipeline actually was inspected and repaired, even though only 2,343 miles were located in HCAs. INGAA estimates that approximately 65 percent of total transmission mileage will have been inspected and repaired by the end of the baseline testing period in December of 2012. As pipelines are updated, and as new pipelines are constructed, we believe that number will grow even higher.

It is important to note that the PG&E pipeline segment in San Bruno is located in a high consequence area, and therefore is subject to the integrity management program. According to PG&E, this segment of pipeline was inspected multiple times within the last few years. Before drawing any conclusions about changing the integrity management program, we need to discover and analyze the causes of the San Bruno incident.

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. PHMSA last week proposed to expedite the implementation of the pipeline controller rule. INGAA supports this proposal.

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.

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 they are 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.

Comments on Administration Draft Reauthorization Legislation

Mr. Chairman, as you know, the Obama administration, on September 15th, released a draft bill to reauthorize the Pipeline Safety Act. Given how recently this draft was made public, INGAA is only now starting to receive comments from member companies. Therefore, I can provide only a limited response today.

Class Location and Integrity Management

Section 11 of the draft requires the Secretary of Transportation to undertake a review of the current integrity management program, and by October 31, 2012, make recommendations to Congress on expanding the program beyond populated areas to “additional areas or entire pipelines,” while at the same time making recommendations on whether such upgrades would eliminate the need “class location requirements.”

The class location requirement is a legacy regulatory program for natural gas transmission pipelines. For 40 years, these regulations have required natural gas transmission pipeline operators to conduct continuing surveillance in order to recognize changes in the population in close proximity to pipelines, and to classify segments as being in one of four categories, with one being rural and four being heavy urban. As a pipeline segment moves up in a class number, the operator is required to increase the margin of safety either by installing stronger piping, by reducing operating pressure or by confirming an adequate safety margin through hydrostatic testing. The class location system was created before internal inspection devices were invented and was an early attempt to reduce the likelihood of an accident in a populated area. The current integrity management program addresses what are effectively the same issues, albeit in a much more sophisticated and fact-specific way. INGAA previously has recommended that Congress and PHMSA review a phase-out of what has become a redundant program.

Utilizing integrity management practices outside of populated areas is something that the pipeline industry already is achieving through the overtesting mentioned previously. INGAA, however, believes that it is important to maintain the focus and priority on mitigating risks in populated areas, because this is where pipelines have the greatest potential impact on people. The focus should remain on such areas, and any update to the integrity management rule should remain consistent with that principle.

Excavation Damage Prevention Program

INGAA is surprised that the draft bill does not place an emphasis on additional steps to reduce excavation damage. 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 helped to raise 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. INGAA also recommends developing best practices for state enforcement of one-call programs, and linking the adoption of such best practices with state grant funds.

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. It is clear, however, that miscommunication occurred between the excavators and the pipeline operators.

The fact that these preventable accidents are still happening is evidence 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. Federal pipeline safety policy should encourage every state program to place a high priority on achieving these goals.

Gathering Line Regulation – User Fees

INGAA does not take a position on whether natural gas gathering lines should be regulated under the Pipeline Safety Act. We note, however, that should Congress adopt such a change, current law would dictate that the costs incurred by PHMSA to regulate gas gathering lines (as well as the cost of PHMSA grants to assist the states with such regulation) would be paid by natural gas transmission pipeline operators. This is because the statute governing user fees – 49 USC 60301 – limits the collection of user fees (in the natural gas sector) to “transmission” gas pipeline operators. Transmission pipeline operators and the customers paying such pipelines’ rates should not be compelled to pay the costs associated with regulating another pipeline sector. If Congress chooses to extend regulation under the Pipeline Safety Act to natural gas gathering lines, we urge that Section 60301 be amended to authorize PHMSA to collect user fees from gathering pipeline operators.

Cost Recovery for Design Reviews

INGAA members already help to fund the pipeline safety program at PHMSA through pipeline safety user fees, as previously mentioned. The PHMSA budget includes the personnel and dollars associated with the design review of natural gas pipeline projects. Absent a provision to exclude the cost of natural gas pipeline design review from the program costs that serve as the basis for the generally applicable user fees, the proposed new authorization to collect these fees would be appear to be double-dipping for an activity whose costs are already being recovered. INGAA therefore opposes this provision.

Special Permits

INGAA is concerned regarding the implications of the proposed amendment to section 60118(c) that would provide a five-year term for the waiver of operating requirements and successive renewal terms of not more than five years. In almost all special permit cases, pipeline operators make significant capital investments in alternate technologies that achieve the same or greater level of safety as required under current regulations. Given the economic characteristics of the natural gas transmission pipeline industry (e.g., capital intensive, long-lived assets) the method by which pipeline transportation rates are established under FERC regulation, such investments are recovered over long periods (sometimes up to 30 years) that greatly exceed the proposed five-year term for waivers. The risk created by a statutory provision that would authorize the revocation of special permits after five years will have a chilling effect on pipeline operators’ willingness to make large capital investments in deploying new technologies that will lead to improved safety performance of the nation's pipeline systems.

HR 6008, the CLEAN Act

INGAA appreciates the purpose of this legislation to ensure that the National Response Center will be alerted to a pipeline release as soon as possible. The law should be flexible, however, in giving a pipeline enough time to determine whether an alarm is accurate, and if so, where the release is occurring. Providing inaccurate or incomplete information to first responders is a potentially counterproductive outcome. We therefore recommend that the amount of time allowed in proposed section 60138(b) be modified to "not later than two hours following the time of such discovery."

Conclusion

Mr. Chairman, pipeline safety has received widespread attention in recent days. Like everyone else, INGAA and its member companies want to use the lessons learned from the tragic events in San Bruno to improve the safety of natural gas transmission pipelines. But before that, we must first learn what caused the accident. INGAA supports an assessment of the pipeline safety program that is driven by solid technical analysis, so that changes in the law, the regulations and the implementation of those requirements will have the greatest likelihood of achieving actual improvements in pipeline safety. We pledge to work with you in making constructive improvements.

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.