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GAS PIPELINE SAFETY

Preliminary Observations on the Implementation of the Integrity Management Program

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Physical Infrastructure Issues

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Mr. Chairman and Members of the Subcommittee:

We appreciate the opportunity to participate in this oversight hearing on the Pipeline Safety Improvement Act of 2002. The act strengthens federal pipeline safety programs and enforcement, state oversight of pipeline operators, and public education on pipeline safety. The information that we and others will provide today should help the Congress as it prepares to reauthorize pipeline safety programs.

My statement is based on the preliminary results of our ongoing work for this Subcommittee and others. As directed by the 2002 act, we are assessing the effects on safety stemming from (1) the Pipeline and Hazardous Materials Safety Administration's (PHMSA) integrity management program for gas transmission pipelines and (2) the requirement that pipeline operators reassess their natural gas pipelines for certain safety risks at least every 7 years.[1] In addition, I would also like to briefly touch on how PHMSA has acted to strengthen its enforcement program. I testified on PHMSA's enforcement program before this Subcommittee almost 2 years ago,[2] and believe that this is a good opportunity to update you on some positive accomplishments.

[1]Under integrity management, operators systematically assess the portions of their pipelines that are in highly populated or frequented areas (such as parks) for safety risks. Although the gas integrity management program applies to natural, toxic, and corrosive gases, the overwhelming majority of gas pipelines in the United States carry natural gas. Our work therefore focuses on natural gas. Transmission pipelines transport gas products from sources to communities and are primarily interstate. Distribution pipelines (local distribution companies) that carry natural gas to ultimate users, such as homes, are not subject to the 2002 act.

[2]GAO, *Pipeline Safety: Preliminary Information on the Office of Pipeline Safety's Actions to Strengthen Its Enforcement Program*, GAO-04-985T (Washington, D.C.: July 20, 2004) and GAO, *Pipeline Safety: Management of the Office of Pipeline Safety's Enforcement Program Needs Further Strengthening*, GAO-04-801 (Washington, D.C.: July 23, 2004).

Our work is based on our review of laws, regulations, and other PHMSA guidance, as well as discussions with a broad range of stakeholders, including industry trade associations, pipeline safety advocate groups, state pipeline agencies, pipeline inspection contractors, and consensus standards organizations.[3] In addition, we surveyed the 47 state pipeline agencies responsible for inspecting intrastate gas transmission pipeline operators on their plans for conducting inspections of operators' integrity management programs.[4] We also contacted 41 pipeline operators about the matters that I will discuss today. We chose operators for which integrity management could have the greatest impact, all else being equal: larger and smaller operators with the highest proportion of pipelines in highly populated or frequented areas to total miles of pipeline. These operators represent about 60 percent of the miles of pipeline assessed to date. We relied on pipeline operators' professional judgment in reporting on the conditions that they found during their assessments of safety risks. The information that we obtained from the 41 operators is not necessarily generalizable to all operators. As part of our work, we assessed the internal controls and the reliability of the data elements needed for this engagement, and we determined that the data elements were sufficiently reliable for our purposes. We performed our work in accordance with generally accepted government auditing standards from August 2005 to April 2006.

[3]Standards are technical specifications that pertain to products and processes, such as the size, strength, or technical performance of a product. National consensus standards are developed by standard-setting entities on the basis of an industry consensus. PHMSA's regulations incorporate standards, including reassessment standards, developed by the American Society of Mechanical Engineers: *Managing the System Integrity of Gas Pipelines* (ASME B31.8S-2004) and the National Association of Corrosion Engineers: *Standard Recommended Practice -Pipeline External Corrosion Direct Assessment* (NACE RP0502-2002).

[4]For the purpose of this statement, we treat the District of Columbia as a state pipeline agency.

In summary:

- Implementation of integrity management is in its early stages as PHMSA's regulations were finalized in 2004. Early indications suggest that the gas integrity management program has enhanced public safety by requiring that operators identify and address the risks to pipeline segments located in areas that are most likely to affect public safety. Operators believe that the primary benefit of the program is the comprehensive knowledge they must acquire about the condition of their pipelines. However, operators have raised concerns about (1) their uncertainty over the level of documentation required by the program and (2) whether the requirement to reassess their pipelines at least every 7 years contributes to increased safety. PHMSA's initial inspections of 13 interstate operators' integrity management programs have shown that operators are doing well in assessing their pipelines and making repairs but that they need to better document their management practices and decisions. Most state pipeline officials reported that they have started or will start integrity management inspections of intrastate operators this year. While state officials reported that they generally agree that integrity management enhances public safety, most are facing challenges in the areas of staffing and training.

- Overall, pipeline operators have reported to PHMSA that, in the 6,700 miles of pipeline in highly populated or frequented areas they have assessed, they have found 338 problems that required immediate repair or replacement[5]—about 1 problem every 20 miles, on average. The 41 operators that we contacted—which represent about 60 percent of the 6,700 miles assessed so far—told us that, if the 7-year requirement were not in place, they would reassess the pipeline segments located in highly populated or frequented areas every 10, 15, or 20 years following industry consensus standards.[6] The 7-year reassessment requirement reflects a midpoint in relation to industry standards for pipelines operating under higher stress (pipelines with higher operating pressure in relation to wall strength) where as the industry standard for reassessments is 10 years or less. (The industry standard requires that pipelines be reassessed at least every 5 years if all repairs are not made. PHMSA's regulations require that repairs be made as necessary.) However, operators told us that the 7-year reassessment requirement is conservative for pipelines operating under lower stress, where as the industry reassessment standard can extend to 15 to 20 years. The large majority of transmission pipelines in the U.S. are estimated to be higher-stress pipelines, based on information from industry associations. Most operators of lower-stress pipelines (21 of the 26 we contacted) told us that they found few problems during baseline assessments that would require reassessments before 15 or 20 years. Operators that we contacted believed that periodic reassessments of their

[5]Operators have reported that about 20,000 miles of pipeline are located in highly populated or frequented areas. Operators are required to make immediate repairs to their pipelines if they (1) determine the remaining strength of the pipe shows a predicted failure pressure of less than or equal to 1.1 times the maximum allowable operating pressure; (2) identify a dent that has any indication of metal loss, cracking, or a stress riser; or (3) determine, in their judgment, the assessment results require immediate action. Stress risers are corrosion, gouges, or cracks within or between dents.

[6]The standards have been accepted by the American National Standards Institute, a private, non-profit organization whose mission is to promote and facilitate voluntary consensus standards and promote their integrity. The Institute does not approve the technical merits of proposed national standards. Rather it ensures that proposed national standards are developed in an environment of openness, balance, consensus, and due process.

pipelines would be beneficial in finding and preventing problems. However, they favored conducting reassessments based on severity of risk rather than applying a one-size-fits-all standard. Operators told us that requiring that pipelines be reassessed more frequently than required under industry standards increases costs—which are ultimately passed to consumers—but does not increase safety. Operators did not expect that the existence of an "overlap period" from 2010 through 2012, when operators will be completing baseline assessments and beginning some reassessments at the same time, would create problems in finding resources to conduct reassessments.[7] The existence of an overlap had been an industry concern while the 2002 act was being debated.

- PHMSA has developed a reasonable enforcement strategy framework that is responsive to concerns we raised in 2004 that PHMSA had not incorporated into its enforcement strategy key features of effective program management—clear program goals, a well- defined strategy for achieving those goals, and performance measures linked to the program goals. PHMSA's recently developed strategy is aimed at reducing pipeline incidents and damage through both direct enforcement and prevention. The strategy entails, among other things, (1) using risk-based enforcement that clearly reflects potential risk and seriousness and dealing severely with operators' significant noncompliance and repeat offenses; (2) increasing knowledge of and accountability for results by clearly communicating expectations for operators' compliance; (3) developing comprehensive guidance tools, along with training inspectors on their use; and (4) effectively using state inspection capabilities.

[7] Under the 2002 act, operators have until 2012 to complete their baseline assessments. However, under the 7-year reassessment requirement, operators that started their baseline assessments in 2003 would then need to reassess those pipeline segments in 2010.

Background

On average, about 3 people have died and about 8 people have been injured annually over the last 10 years in natural gas transmission pipeline incidents. The number of incidents has increased from 77 in 1996 to 122 in 2004 and 200 in 2005, primarily due to the greater frequency of property damage.[8] Much of this increase may be attributed to the rise in the price of gas (which has the effect of lowering the reporting threshold) over the past several years and to damage as a result of hurricanes in 2005.

As a means of enhancing the security and safety of gas pipelines, the 2002 act included an integrity management structure that, in part, requires operators of gas transmission pipelines to systematically assess for safety risks the portions of their pipelines located in highly populated or frequently used areas, such as parks. Safety risks include corrosion, welding defects and failures, third-party damage (e.g., from excavation equipment), land movement, and incorrect operation. The act requires that operators perform these assessments (called baseline assessments) on half of the pipeline mileage in highly populated or frequented areas by December 2007 and the remainder by December 2012. Those pipeline segments potentially facing the greatest risks are to be assessed first. Operators must then repair or replace any defective pipelines. Performing this form of risk-based assessment is seen by many as having a greater potential to improve safety than focusing on compliance with safety standards regardless of the threat to pipeline safety.

The act further provides that pipeline segments in highly populated or frequented areas must be reassessed for safety risks at least every 7 years.

[8]An incident, for PHMSA reporting purposes, involves a death; injury requiring hospitalization; or property damage, including any loss of natural gas during an incident, of $50,000 or more.

PHMSA's regulations implemented the act by requiring that operators reassess their pipelines for corrosion damage every 7 years using an assessment technique called confirmatory direct assessment.[9] Under these regulations, and mostly consistent with industry national consensus standards,[10] operators must also reassess their pipeline segments for safety risks at least every 10, 15, or 20 years, depending on the pressure under which the pipeline segments are operated and the condition of the pipeline.

There are about 900 operators of about 300,000 miles of gas transmission and gathering pipelines in the United States. As of December 2005, according to PHMSA, 429 of these operators reported that about 20,000 miles of their pipelines are located in highly populated or frequented areas (about 7 percent of all transmission pipeline miles). Operators reported that they had as many as about 1,600 miles and as few as 0.02 miles of pipeline in these areas.

PHMSA, within the Department of Transportation, administers the national regulatory program to ensure the safe transportation of gas and hazardous liquids (e.g., oil, gasoline, and anhydrous ammonia) by pipeline. The agency attempts to ensure the safe operation of pipelines through regulation, national consensus standards, research, education (e.g., to prevent excavation-related damage), oversight of the industry through inspections, and enforcement when safety problems are found. In general, PHMSA retains full responsibility for inspecting and enforcing regulations

[9] Confirmatory direct assessment allows for less extensive use of testing methods and is meant to provide assurance that drastic damage is not taking place. Confirmatory direct assessment allows an operator to obtain interim results until it performs a full reassessment.

[10] As discussed earlier, PHMSA's regulations do not provide for the 5-year reassessment interval that are contained in the industry national consensus standards.

on interstate pipelines but certifies states to perform these functions for intrastate pipelines. PHMSA employs about 165 staff in its pipeline safety program, about half of whom are pipeline inspectors who inspect gas and hazardous liquid pipelines under integrity management and other more traditional compliance programs. Nine PHMSA inspectors are currently devoted to the gas integrity management program. State pipeline agencies have about 325 inspectors, about 100 of which are currently able to perform integrity management inspections of intrastate gas transmission pipeline operators in 47 states.

Early Indications Suggest that Gas Integrity Management Enhances Public Safety, but Operators and States Raise Some Concerns About Implementation

While the gas integrity management program is still being implemented, early indications suggest that it enhances public safety by supplementing existing safety standards with risk-based management principles. Prior to the integrity management program, there were, and still are, minimum safety standards that operators must meet for the design, construction, testing, inspection, operation, and maintenance of gas transmission pipelines. These standards apply equally to all pipelines and provide the public with a basic level of protection from pipeline failures. However, minimum standards do not require operators to identify and address risks that are specific to their pipelines, nor do they require operators to assess the integrity of their pipelines. While some operators have assessed the integrity of some of their pipelines, others have not. Consequently, some pipelines have operated for 40 or more years with no assessment. The gas integrity management requirements, finalized in 2004, go beyond the existing safety standards by requiring operators, regardless of size, to routinely assess pipelines in highly populated or frequented areas for specific threats, to take action to mitigate the threats, and to document management practices and decision-making processes.

Representatives from the pipeline industry, safety advocate groups, state pipeline agencies, and operators we have contacted agree that the integrity management program enhances public safety. Some operators noted that, although the program's requirements can be costly and time consuming to implement, the benefits to date are worth the costs. The primary benefit identified was the comprehensive knowledge the program requires all operators to have of their pipeline systems. For example, under integrity management, operators must gather and analyze information about their pipelines in highly populated or frequented areas to get a complete picture of the condition of those lines. This includes developing maps of the pipeline system and gathering information on corrosion protection, exposed pipeline, threats from excavation or other third-party damage, and the installation of automatic shut-off valves. Another benefit cited was improved communications within the company. Investigations of pipeline incidents have shown that, in some cases, an operator possessed information that could have prevented an incident but had not shared it with employees who needed it most. Integrity management requires operators to pull together pipeline data from various sources within the company to identify threats to the pipelines, leading to more interaction among different departments within pipeline companies. Finally, integrity management focuses operator resources on those areas where an incident could have the greatest impact.

While industry and operator representatives have provided examples of the early benefits of integrity management, operators must report semiannually on performance measures that should quantitatively demonstrate the impact of the program over time. These measures include the total mileage of pipelines and the mileage of pipelines assessed in highly populated or frequented areas, as well as the number of repairs made and leaks, failures, and incidents identified in these areas. In the 2 years that operators have reported the results of integrity management, they have assessed about 6,700 miles of their 20,000 miles of pipelines located in highly populated or frequented areas, and they have completed 338 repairs that were immediately required and another 998 repairs that were less urgent. While it is not possible to determine how many of these needed repairs would have been identified without integrity management, it is clear that the requirement to routinely assess pipelines enables operators to identify problems that may otherwise go undetected. For example, one operator told us that it had complied with all the minimum safety standards on its pipeline, and the pipeline appeared to be in good condition. The operator then assessed the condition of a segment of the pipeline under its integrity management program and found a serious problem, causing it to shut the line down for immediate repair.

One of the most frequently cited concerns by the 41 operators we contacted was the uncertainty about the level of documentation needed to support their gas integrity management programs. PHMSA requires operators to develop an integrity management program and provides a broad framework for the elements that should be included in the program. Each operator must develop and document specific policies and procedures to demonstrate its commitment to compliance with and implementation of the integrity management requirements. In addition, an operator must document any decisions made related to integrity management. For example, an operator must document how it identified the threats to its pipeline in highly populated or frequented areas and who was involved in identifying the threats, their qualifications, and the data they used. While the operators we contacted agreed with the need to document their policies and procedures, some said that the detailed documentation required for every decision is very time consuming and does not contribute to the safety of pipeline operations. Moreover, they are concerned that they will not know if they have enough documentation until their program has been inspected. After conducting 13 inspections, PHMSA found that, while interstate operators are doing well in conducting assessments and making the identified repairs, they are having difficulty overall in the development and documentation of their management processes. Another concern raised by most of the operators is the requirement to reassess their pipelines at least every 7 years. I will discuss the 7-year reassessment requirement in more detail shortly.

In response to our survey, most state officials indicated that the two most challenging areas for them as they begin implementing gas integrity management inspections are staffing and training. While most state agencies currently have at least two inspectors that can perform inspections of operators' integrity management programs, some state pipeline officials responded that they do not have enough inspectors for the increased workload and/or their inspectors have not completed the training required by PHMSA. To ensure that inspectors have the technical expertise to conduct integrity management inspections, including evaluating operators' processes and decisions, PHMSA requires inspectors to complete 4 classroom and 6 computer-based courses, totaling about 19 days of training. Three of the classroom courses are part of PHMSA's core training for all inspectors and are generally offered annually. The fourth course—a new course that PHMSA established for integrity management—was made available to two inspectors from each state in 2005 and is now offered when there is sufficient demand. The computer-based courses were made available to the states starting in February 2005. While the state officials we spoke with agree that the training is necessary, they are concerned about the amount of time it takes to complete the required training and the limited availability of the classroom training. We will continue to follow up with state agencies about how these challenges will affect their oversight activities.

I am pleased to report that in response to our 2002 recommendation,[11] PHMSA has been working to improve its communication with states about their role in overseeing integrity management programs. For example, PHMSA's efforts include (1) inviting state inspectors to attend federal inspections, (2) creating a Web site containing inspection information, and (3) providing a series of updates through the National Association of Pipeline Safety Representatives. Results from the survey of state pipeline agencies (with most of the states responding thus far) show that the majority of state agencies believe that communication from PHMSA has been very or extremely useful in helping them understand their roles and responsibilities in conducting integrity management inspections.[12]

7-Year Reassessment Requirement May be Appropriate for Some Operators but Conservative for Others

Nationwide, pipeline operators reported to PHMSA that they have found, on average, about one problem requiring immediate repair or replacement for every 20 miles of pipeline assessed in highly populated or frequented areas. Operators we contacted recognize the benefits of reassessments; however, almost all would prefer following the industry national consensus standards that use safety risk, rather than a prescribed term, for determining when to reassess their pipelines. Most operators expect to be able to acquire the services and tools needed to conduct these

[11]GAO, *Pipeline Safety and Security: Improved Workforce Planning and Communication Needed*, GAO-02-785 (Washington, D.C.: Aug. 26, 2002).

[12]Of the 46 state agencies that responded, three state agencies indicated that PHMSA information was extremely useful, 23 state agencies said the information was very useful, 9 state agencies said it was moderately useful, 5 said it was somewhat useful, 1 said it was not useful, and 5 had no opinion.

reassessments, including during the overlap period when they are starting to reassess pipeline segments while completing baseline assessments.

Operators Favor a Risk-based, Rather than a One-Size-Fits-All, Reassessment Standard

As discussed earlier, as of December 2005, operators nationwide have notified PHMSA of 338 problems that required immediate repair in the 6,700 miles in highly populated or frequented areas that they have assessed—about one immediate repair required for every 20 miles of pipeline assessed in highly populated or frequented areas.[13] The number of immediate repairs may be due, in part, to some operators systematically assessing their pipelines for the first time as a result of the 2002 act.

We contacted 41 transmission operators and local distribution companies about their assessment activities. These operators represent about 60 percent of the 6,700 miles assessed nationwide. Of these, 38 have begun assessments and 32 (84 percent) told us that they found few safety problems that required reducing pressure and performing immediate repairs during baseline assessments. These assessments covered (1) about 4,100 miles of pipeline in highly populated or frequented areas and (2) about 30,000 miles outside of these areas.[14] (See fig. 1.) Twenty-five of these 38 operators reported finding pipelines in good condition and free of major defects, requiring only minor repairs or recoating. Seven of these operators found two or fewer problems per 100 miles that require

[13]Most operators found no or few problems and a handful found more than 10 problems overall requiring immediate repair. We hope to portray these results when we report to this Subcommittee and others this fall.

[14]For example, pipeline operators told us that, when they run an in-line inspection tool through a pipeline, they do not collect data solely within the boundary of the highly populated or frequented area if the insertion and retrieval points for the tool extend beyond the highly populated or frequented area. Rather, they gather information on the pipeline's condition for the entire distance between the insertion and retrieval points because, in doing so, they gather additional insights into the condition of their pipeline.

immediate repairs. Finally, six operators found five or more immediate repairs per 100 miles assessed.[15] Operators nonetheless found these assessments valuable in determining the condition of their pipelines and finding damage. The large proportion of these operators reporting that they found no or few problems requiring immediate repair is encouraging if they represent assessments of their segments facing the greatest risk, as required by the 2002 act.

[15] In figure 1, the results for operator Hi12 show a greater number of problems requiring immediate repair (per 100 miles assessed) because it has assessed 11 miles and found 2 of these problems. The other two operators showing the largest number of problems per 100 miles requiring immediate repair, Lo25 and Lo26, have assessed 77 miles and 370 miles, respectively.

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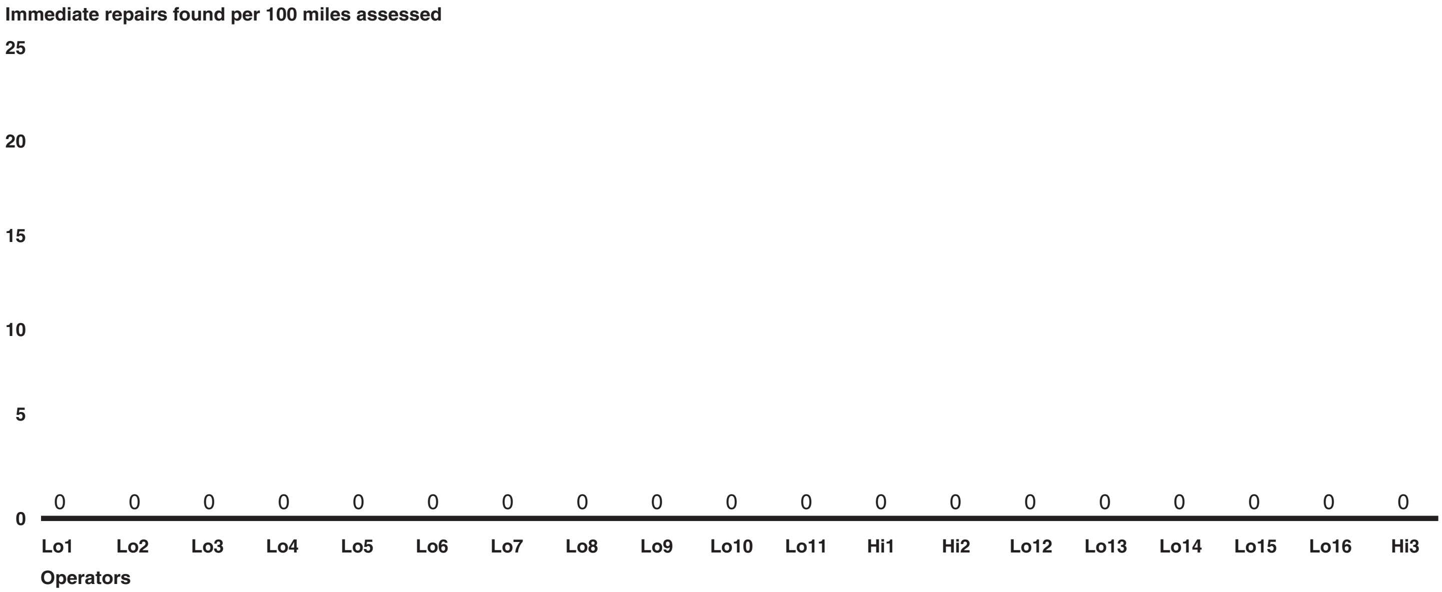
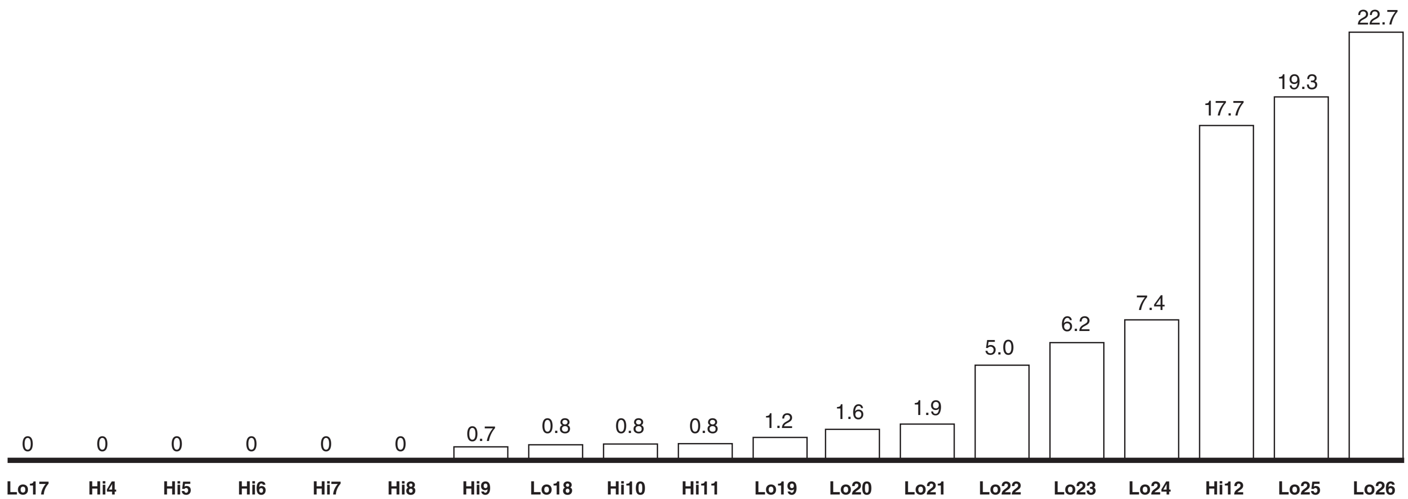
Figure 1: Number of Immediate Repairs Needed as Found During Baseline Assessments



Source: GAO interviews with operators.



Note: The Hi and Lo prefixes to the operator designations denote higher stress and lower stress pipelines, respectively. To prevent distortion, we excluded 3 of the 41 operators we contacted because they had assessed 0 miles of pipeline to date. This figure includes the immediate repairs for pipeline located both inside and outside of highly populated or frequented areas.

The results for operator Hi12 show a greater number of problems requiring immediate repair (per 100 miles assessed) because it has assessed 11 miles and found 2 of these problems. The other two operators showing the largest number of problems per 100 miles requiring immediate repair, Lo25 and Lo26 have assessed 77 miles and 370 miles, respectively.

Of the 38 operators that have begun assessment activities, 22 have calculated reassessment intervals.[16] These operators indicated that based on the conditions that they identified during baseline assessments; they could reassess their pipelines at intervals of 10, 15, or 20 years -- as allowed by industry consensus standards[17] -- if the 7-year reassessment requirement were not in place. In some cases, operators chose to reassess

[16]The other 16 operators either (1) have not calculated reassessment intervals; (2) do not intend to, given the prescriptive federal (7 years) or state (5 years in Texas) reassessment requirements; or (3) did not supply us information on their reassessment intervals.

[17] As discussed earlier, the development of these standards met the American National Standards Institute's requirements for openness, balance, consensus, and due process.

their pipelines at intervals shorter than the industry standards based on their own discretion. These baseline assessment findings suggest that overall—at least for the operators we contacted—the 7-year requirement is conservative.

The 7-year reassessment interval represents an approximate midpoint between the 5- and 10-year industry reassessment requirements for pipelines operating under higher-stress. (The industry standard requires that pipelines be reassessed at least every 5 years if all repairs are not made. PHMSA's regulations require that repairs be made as necessary.) Higher-stress transmission pipelines are typically those that transport natural gas across the country from a gathering area to a local distribution company. Operators pointed out that reassessing their pipelines in 7 rather than 10 years creates additional costs without an equivalent gain in safety; that is, if the 7-year interval requirement were not in place they would not reassess their pipelines for another 3 years consistent with industry standards. Operators added that the costs of the more frequent reassessments will eventually be passed on to customers. PHMSA does not collect information in such a way that would allow us to readily estimate the percentage of all pipeline miles in highly populated or frequented areas that operate under higher pressure. In the aggregate, the 41 operators that we contacted told us that more than three-fourths of their pipeline mileage in highly populated or frequented areas is operated under higher pressure. Finally, industry data suggest that in the neighborhood of 250,000 miles of the 300,000 miles (over 80 percent) of all transmission pipelines nationwide may operate under higher pressure.

Some operators told us that the 7-year reassessment requirement is conservative for pipelines that operate under lower stress. This is especially true for local distribution companies that use their transmission lines mainly to transport natural gas under lower pressure for several miles from larger cross-country lines in order to feed smaller distribution lines. They pointed out, for example, that in a lower-pressure environment, pipelines tend to leak rather than rupture. Leaks involve controlled, slow emissions that typically pose little damage or risk to public safety. Twenty-one of the 26 lower stress operators (most of which are local distribution companies) we contacted that have begun assessments reported finding few, if any, conditions during baseline assessments that would require immediate repair. (See fig. 1 and accompanying note.) As a result, if the 7-year requirement did not exist, these local distribution companies would likely reassess every 15 to 20 years, following industry consensus standards. Some of these operators pointed out that third-party damage poses the greatest threat to their systems. Operators added that third-party damage, such as dents caused by excavation, can happen at any time and that prevention and mitigation measures are the best ways to address it.[18]

Operators viewed a risk-based reassessment requirement, such as in the consensus standard, as valuable for public safety. Operators of both higher-stress and lower-stress pipelines indicated a preference for a risk-based reassessment requirement based on engineering standards rather than a prescriptive one-size-fits-all standard.[19] In addition, a risk-based reassessment standard would be consistent with the overall thrust of the integrity management program. Some operators noted that reassessing

[18]Prevention and mitigation measures include one-call programs, proper marking of the pipeline's location, inspection by air, and public education programs. In one-call programs, persons who want to dig in an area contact a clearinghouse. The clearinghouse notifies pipeline operators and others that someone is going to be digging near the pipeline so that the operator can mark the pipeline's location prior to the digging work.

[19]On a related note, the Congress expressed a general preference for technical standards developed by consensus bodies over agency-unique standards in the National Technology Transfer and Advancement Act of 1995.

pipeline segments with few defects every 7 years takes resources away from riskier segments that require more attention. While PHMSA's regulations require that pipeline segments be reassessed only for corrosion problems at least every 7 years using the less intensive assessment technique of confirmatory direct assessment, some operators point out that it has not worked out that way. They told us that, if they are going to the effort of assessing pipeline segments to meet the 7-year reassessment requirement, they will typically use more extensive testing—both for corrosion and other problems—than required, because doing so will provide more comprehensive information. Thus, in most cases, operators plan to reassess their pipelines by using the more extensive in-line inspections or direct assessment for problems in addition to corrosion sooner than required under PHMSA's rules.[20]

Finally, operators are required by PHMSA to take actions in addition to periodically reassessing their pipelines. Operators must, on an ongoing basis, evaluate their pipelines by integrating operational data with other information, including assessment data and risk assessment information, to assure the integrity of their pipelines. Operators will use the results from the evaluation to identify and remediate specific pipeline threats and associated risks.

[20]Direct assessment is a four-step procedure used to identify corrosion and other pipeline defects. First, operators analyze information about the physical characteristics of a pipeline, such as coating, soil moisture, and past leaks. Second, operators use one or more tools to examine the pipeline through the soil in areas identified in the first step. Third, operators use the results of the above-ground examination to dig holes in intervals along the pipeline to examine suspected pipeline problem areas. Finally, operators integrate and analyze information gathered during the three previous steps to determine when additional digging is necessary and how often pipeline segments should be reassessed.

Services and Tools Are Likely to be Available for Reassessments

Thirty-four of the 41 operators and 4 inspection contractors and 1 association we contacted (85 percent) told us that the services and tools needed to conduct periodic reassessments will likely be available to most operators.[21] All but one of the operators reported that they plan to rely on contractors to conduct all or a portion of their reassessments, and eight of the 41 operators have signed, or would like to sign, long-term contracts that extend contractor services through a number of years. However, few have scheduled reassessments with contractors, as reassessments will take place several years in the future, and operators are concentrating on baseline assessments.

Thirty of the 38 operators (79 percent) that reported both baseline and reassessment schedules to us said that they primarily plan to use in-line inspection or direct assessment to reassess segments of their pipelines located in highly populated or frequented areas. In-line inspection contractors that we contacted report that there is capacity within the industry to meet current and future operator demands. Unlike the in-line inspection method, which is an established practice that 25 of 41 operators have used on their pipelines at least once prior to the integrity management program, the direct assessment method is new to both contractors and operators. Direct assessment contractors told us that there is limited expertise in this field, and one contractor said that newer contractors coming into the market to meet demand may not be qualified. The operators planning to use direct assessment for their pipelines are

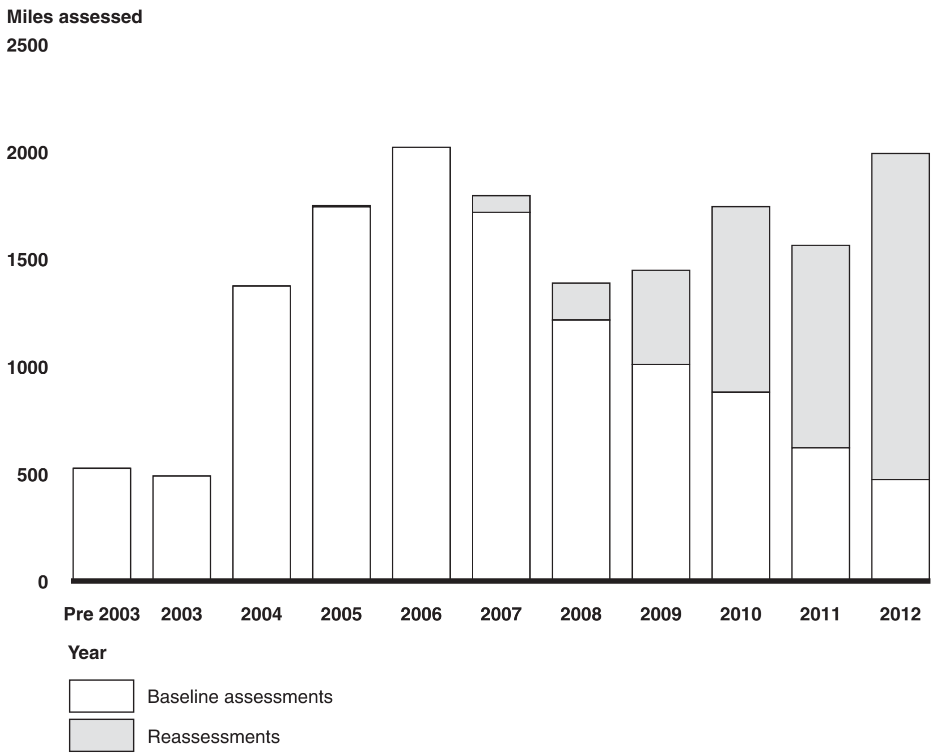
[21]To prepare for this hearing, we contacted the Inline Inspection Association, two companies offering in-line inspection services, and two companies offering direct assessment services.

generally local distribution companies with smaller diameter pipelines that cannot accommodate in-line inspection tools.[22]

An industry concern about the 7-year reassessment requirement is that operators will be required to conduct reassessments starting in 2010 while they are still in the 10-year period (2003-2012) for conducting baseline assessments. Industry is concerned that this could create a spike in demand for contractor services resulting from an overlap of assessments and reassessments from 2010 through 2012, and operators would have to compete for the limited number of contractors to carry out both. The industry was worried that operators might not be able to meet the reassessment requirement and that it was unnecessarily burdensome.[23] However, the information provided by the operators that we contacted does not suggest a spike and because baseline assessment activity should decrease as they begin to conduct reassessments. (See fig. 2.) Operators predict that they will have conducted a large number of baseline assessments between 2005 and 2007 in order to meet the statutory deadline for completing at least half of their baseline assessments by December 2007 –two years before the predicted overlap.

[22]According to industry estimates, 35 percent of all local distribution company pipelines (as measured in miles likely to be located in highly populated areas) cannot accommodate an in-line inspection tool, compared to only about 4 percent of transmission operators' pipelines.

Figure 2: Operators' Planned Baseline Assessment and Reassessment Schedules



Source: GAO.

Note: This figure shows the baseline assessments conducted, or planned to be conducted, as well as the reassessments that are planned in highly populated or frequented areas for the 38 of 41 operators we contacted. Three operators did not report their reassessment plans.

There has also been a concern about whether baseline assessments and reassessments would affect the natural-gas supply if pipelines are taken out of service or operate at reduced pressure when repairs are being made. We are addressing this issue and will report on it in the fall.

[23] The 2002 act allows operators to request a waiver from conducting reassessments when inspection tools are not available and when operators need to maintain product supply. PHMSA has not issued guidance on conditions under which it would grant a waiver.

PHMSA Has Developed a Reasonable Framework for Its Enforcement Program

In 2004, we concluded that we could not assess the effectiveness of PHMSA's enforcement strategy because it had not incorporated key features of effective program management—clear program goals, a well-defined strategy for achieving those goals, and performance measures that link to the program goals.[24] In response to our concerns, PHMSA adopted a strategy in August 2005 that focuses on using risk-based enforcement, increasing knowledge of and accountability for results, and improving its own enforcement activities. The strategy also links these efforts to goals to reduce and prevent pipeline incidents and damage, in addition to providing for periodic assessment of results. While we have neither reviewed the revised strategy in depth nor examined how it is being implemented, our preliminary view is that it is a reasonable framework that is responsive to the concerns that we raised in 2004.

PHMSA has established overall goals for its enforcement program to reduce incidents and damage due to operators' noncompliance. PHMSA also recognizes that incident and damage prevention is important, and its strategy includes a goal to influence operators' actions to this end. To meet these goals, PHMSA has developed a multi-pronged strategy that is directed at the pipeline industry and stakeholders (such as state regulators), ensures that its processes make effective use of its resources.

For example, PHMSA's strategy calls for using risk-based enforcement to, among other things, take enforcement actions that clearly reflect potential risk and seriousness and deal severely with significant operator noncompliance and repeat offenses. Second, the strategy calls for increasing knowledge of and accountability for results through such actions as (1) soliciting input from operators, associations, and other

[24] GAO-04-801.

stakeholders in developing and refining regulations, inspection protocols, and other guidance; (2) clearly communicating expectations for compliance and sharing lessons learned; and (3) assessing operator and industry compliance performance and making this information available. Third, the strategy, among other things, calls for improving PHMSA's own enforcement activities by developing comprehensive guidance tools, training inspectors on their use, and effectively using state inspection capabilities.

Finally, to understand the progress being made in encouraging pipeline operators to improve their level of safety and, as a result, reduce accidents and fatalities, PHMSA annually will assess its overall enforcement results as well as various components of the program. Some of the program elements that it may assess are inspection and enforcement processes, such as the completeness and availability of compliance guidance, the presentation of operator and industry performance data, and the quality of inspection documentation and evidence.

Concluding Observations

Our work to date suggests that PHMSA's gas integrity management program should enhance pipeline safety, and operators support it. We have not identified issues that threaten the overall framework of integrity management. We expect to provide additional insights into issues involving state pipeline agency staffing and training and the 7-year reassessment requirement when we report to this Subcommittee and others this fall.

Because the program is in its early phase of implementation, PHMSA is learning how to oversee the program, and operators are learning how to meet its requirements. Similarly, operators are in the early stages of assessing their pipelines for safety problems. This means that the integrity management program will be going through this shakedown period for another year or two as PHMSA and operators continue to gain experience.

Mr. Chairman, this concludes my prepared statement. I would be pleased to respond to any questions that you or the other Members of the Subcommittee might have.

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