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GAS PIPELINE SAFETY

Views on Proposed Legislation to Reauthorize Pipeline Safety Provisions

Statement for the Record by
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Physical Infrastructure Issues

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Highlights

Highlights of GAO-06-1027T, a testimony before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, House of Representatives

GAS PIPELINE SAFETY

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Why GAO Did This Study

The Pipeline Safety Improvement Act of 2002 established a risk-based program for gas transmission pipelines—termed integrity management—which requires pipeline operators to identify areas where the consequences of a pipeline incident would be the greatest, such as highly populated areas. Operators must assess pipelines in these areas for safety threats (such as corrosion), repair or replace defective segments, and reassess their pipelines at least every 7 years. Under the Pipeline and Hazardous Materials Safety Administration's (PHMSA) regulations, operators must reassess their pipelines for corrosion at least every 7 years and for all safety threats at least every 10, 15, or 20 years. State pipeline safety agencies that assist PHMSA are eligible to receive matching funds up to 50 percent of the cost of their pipeline safety programs.

This statement is based on ongoing work for this Subcommittee and for others. It focuses on three areas germane to current legislative reauthorization proposals: (1) an overall assessment of the integrity management program, (2) the 7-year reassessment requirement, and (3) provisions to increase state pipeline safety grants. GAO contacted more than 50 pipeline operators and a broad range of stakeholders and surveyed state pipeline agencies. GAO also reviewed PHMSA and industry guidance and reviewed PHMSA pipeline performance data.

www.gao.gov/cgi-bin/getrpt?GAO-06-1027T.

To view the full product, including the scope and methodology, click on the link above. For more information, contact Katherine Siggerud at (202) 512-2834 or siggerudk@gao.gov.

What GAO Found

While the gas integrity management program is still being implemented, early indications show that the program benefits pipeline safety. For example, the condition of transmission pipelines is improving as operators assess and repair their pipelines. As of December 31, 2005 (latest data available), 33 percent of the pipelines in highly populated or frequently used areas had been assessed and over 2,300 repairs had been completed. In addition, we estimate that up to 68 percent of the population that lives close to natural gas transmission pipelines is located in highly populated areas and is expected to receive additional protection as a result of improved pipeline safety. Furthermore, despite some uncertainty on the part of operators over the program's documentation requirements, operators, gas pipeline industry representatives, state pipeline officials, and safety advocate representatives all agree that the program enhances public safety, citing operators' improved knowledge of the threats to their pipelines as the primary benefit.

Although periodic reassessments of pipeline threats are beneficial, the 7-year reassessment requirement appears to be conservative. Through December 2005, 76 percent of the operators (182 of 241) reporting baseline assessment activity to PHMSA reported that their pipelines were in good condition, requiring only minor repairs. Most of the problems found were concentrated in just 7 pipelines. These results are encouraging, since operators are required to assess their riskiest segments first and operators are required to repair defects, making them safer before reassessments begin toward the end of the decade. There have been no deaths or injuries from corrosion related pipeline incidents over the past 5-1/2 years. An alternative approach is to permit pipeline operators to reassess their pipeline segments at intervals based on technical data, risk factors, and engineering analyses. Such an approach is consistent with the overall philosophy of the 2002 act and would meet its safety objectives. Under this approach, operators could reassess their pipelines at intervals longer than 7 years only if operators can adequately demonstrate that corrosion will not become a threat within the chosen time intervals. Otherwise, the reassessment must occur more frequently. As a safeguard to ensure that operators have identified threats facing these pipeline segments and have determined appropriate reassessment intervals, PHMSA and state regulatory agencies are already conducting integrity management inspections of operators. They plan to inspect most operators' integrity management activities by 2009.

The provision to increase the cap on pipeline safety grants to states appears reasonable given that states' workloads are expanding, but funding sources and oversight of states' expanded activities would need to be addressed in order to ensure that the increased grants are appropriately carried out. PHMSA has identified several potential funding sources, such as reprioritizing the agency's budget and increasing pipeline user fees. For oversight, PHMSA anticipates integrating states' expanded activities into the agency's current oversight approach that relies on annual reports from states and field evaluations.

Mr. Chairman and Members of the Subcommittee:

We appreciate the opportunity to assist the Subcommittee in its efforts to reauthorize the Pipeline Safety Improvement Act of 2002, which strengthened federal pipeline safety programs and enforcement, state oversight of pipeline operators, and public education on pipeline safety. This statement is based on the preliminary results of our ongoing work for this Subcommittee and others on aspects of the integrity management program for gas transmission pipelines established under the 2002 act.[1] We appeared before this subcommittee in April to discuss these topics.[2] This statement focuses on three areas that are related to the Subcommittee's July 20, 2006, draft bill; H.R. 5782, as introduced; and the administration's pipeline reauthorization, introduced as H.R. 5678. These three areas are (1) an overall assessment of the integrity management program, (2) the 7-year reassessment requirement, and (3) provisions to increase state pipeline safety grants.

Our work is based on our review of laws, regulations, pipeline performance data, and other guidance from the federal regulator—the Pipeline and Hazardous Materials Safety Administration (PHMSA)—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] We also reviewed industry consensus standards for maximum reassessment intervals developed by the American Society of Mechanical Engineers. 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

[1]Under integrity management, operators are required to develop programs to systematically assess and mitigate safety threats, such as leaks or ruptures, for the portions of their pipelines that are in highly populated or frequently used areas (such as parks). They must complete baseline assessments by 2012 and then reassess these pipeline segments every 7 years. Under PHMSA's regulations, operators must reassess their pipelines for corrosion at least every 7 years and for all time-dependent safety threats at least every 10, 15, or 20 years. Transmission pipelines transport gas products from sources to communities and are primarily interstate.

[2]GAO, *Gas Pipeline Safety: Preliminary Observations on the Implementation of the Integrity Management Program*, GAO-06-588T (Washington, D.C.: April 27, 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.

management programs.[4] We also contacted 52 pipeline operators. These operators represent nearly 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 threats. Because we used a non-probability method of selecting these operators, we cannot project our findings nationwide.[5] 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 July 2006.

In summary:

- While the gas integrity management program is still being implemented, early indications show that the program benefits pipeline safety, as intended by Congress. First, the condition of transmission pipelines is improving as operators complete their first round of pipeline assessments and make repairs. For example, 33 percent of the identified pipelines in highly populated or frequently used areas had been assessed and over 2,300 repairs had been completed as of December 31, 2005 (latest data available). In addition, we estimate that up to 68 percent of the population that lives close to natural gas transmission pipelines is located in highly populated areas and is expected to receive additional protection as a result of improved pipeline safety as operators complete their baseline assessments by December 2012, as required. Furthermore, despite some uncertainty on the part of operators over the program's documentation requirements, operators, gas pipeline industry representatives, state pipeline officials, and safety advocate representatives all agree that the program enhances public safety, citing operators' improved knowledge of the threats to their pipeline systems that stems from systematic assessments as the primary benefit of the program.

- Regarding the 7-year reassessment requirement, the draft Subcommittee bill would require the Secretary of Transportation to submit a legislative

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

[5] Results from nonprobability samples cannot be used to make inferences about a population because, in a nonprobability sample, some elements of the population being studied have no chance or have an unknown chance of being selected as part of the sample.

proposal after it receives our report on the subject. Our work, which is nearing completion, concludes that periodic reassessments are beneficial, but that the 7-year reassessment requirement appears to be conservative based on a number of factors. Among these are results of the baseline assessments conducted to date and the overall safety record of the gas transmission industry. In this regard, through December 2005, 76 percent of the operators (182 of 241) reporting baseline assessment activity reported to PHMSA that their pipelines were in good condition and free of major defects, requiring only minor repairs. Most of the 340 problems found were concentrated in just 7 pipelines, although it is not known how many of these problems were due to corrosion. (These assessments reported by the 241 operators covered about 6,700 miles, or about one-third of the nationwide total to be assessed by 2012.) These results are encouraging, since operators are required to assess their riskiest segments first. Furthermore, since operators are required to repair these pipelines, the overall safety and condition of the pipeline system should be improved before reassessments begin toward the end of the decade. Regarding safety, PHMSA data show corrosion incidents are relatively rare: over the past 5-1/2 years (from January 2001 through early July 2006), there were 26 corrosion-related incidents over the 295,000-mile transmission system per year, on average—none of which resulted in death or injury.[6]

- The administration's proposal would require the Secretary of Transportation to issue regulations basing reassessment intervals on technical data, risk factors, and engineering analyses. Based on our nearly completed work, we think that this approach is reasonable and would achieve the safety objectives of the 2002 act. It is also consistent with the overall philosophy of the integrity management legislation passed by the Congress in 2002. As discussed later in this statement, if PHMSA incorporates existing industry consensus standards for corrosion into its regulations, operators would be allowed to reassess their pipelines for time-dependent threats at least every 10, 15, or 20 years only if the operator can adequately demonstrate that corrosion will not become a threat within the chosen time interval. If not, then the reassessment must occur more frequently, perhaps at 7 or even fewer years. As a safeguard for ensuring that operators have identified threats facing pipeline segments and have determined appropriate reassessment intervals, PHMSA and state regulatory agencies are already conducting inspections. They plan to inspect most operators' integrity management activities by 2009.

[6]There have been two corrosion-related incidents in the last 10-1/2 years that have resulted in a death or injury. Neither occurred in a highly populated or frequently used area.

- The provision in the Subcommittee's draft bill to increase the cap on pipeline safety grants to states from 50 percent to 80 percent of the cost of their expanded pipeline safety programs appears reasonable given that states' workload is increasing to, among other activities, enforce integrity management requirements and damage prevention programs. However, if Congress approves this provision, two areas would need to be addressed to ensure that the increased grants are appropriately carried out: the source of funding for the increased grant amounts and oversight of the expanded state pipeline safety activities. According to PHMSA, the agency has identified funding options—including reprioritizing the agency's budget to channel funds from other activities (such as research) and increasing user fees charged to pipeline companies —but has not developed a specific plan for how to provide additional funds to states. PHMSA currently oversees state pipeline safety activities through annual reports from the states and field evaluations. According to PHMSA officials, expanded state pipeline safety agency activities would be included in PHMSA's oversight approach.

Background

The United States has a 295,000-mile network of natural gas transmission pipelines that are owned and operated by approximately 900 operators. These pipelines are important to the nation because they transport nearly all the natural gas used, which provides about a quarter of the nation's energy supply. Gas transmission pipelines typically move gas products over long distances from sources to communities and are primarily interstate. They generally deliver natural gas to local distribution pipelines, which distribute the gas to commercial and residential end-users. Local distribution companies may also operate small portions of transmission pipelines.

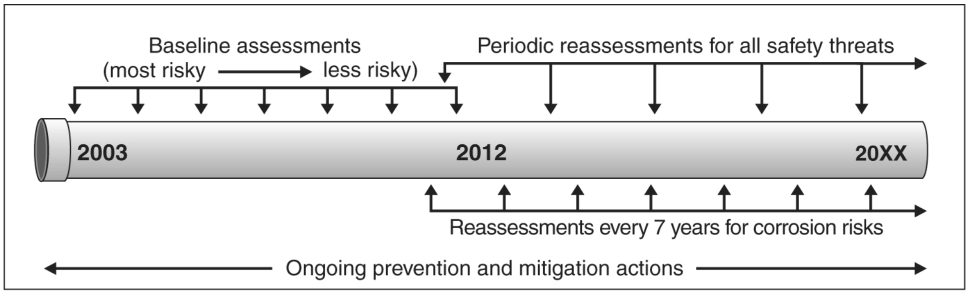
PHMSA administers the national regulatory program to ensure the safe transportation of natural gas and hazardous liquid by pipeline. In general, PHMSA retains full responsibility for inspecting and enforcing regulations on interstate pipelines, but it has arrangements with 48 states, the District of Columbia, and Puerto Rico to assist with overseeing intrastate pipelines. These states are currently authorized to receive reimbursement of up to 50 percent of the costs of their pipeline safety programs from PHMSA.

Traditionally, PHMSA has carried out its oversight role using minimum safety standards that were uniformly applied to all pipelines based on the "class location" of the pipeline. A pipeline's class location—based on factors such as population within 660 feet of the pipeline—determines the applicable standards such as the thickness of the pipe required and the pressure at which it can operate. The Pipeline Safety Improvement Act of 2002 modified PHMSA's traditional oversight approach by supplementing the minimum standards with a risk-based program for gas transmission pipelines. This program—termed "integrity management"—requires gas transmission pipeline operators to assess and mitigate safety threats, such as leaks or ruptures due to incorrect operation or corrosion, to pipeline segments that are located in highly populated or frequently used areas, such as parks. Specifically, operators are required to perform baseline assessments on half of the pipeline mileage located in these areas by December 2007, and the remainder by December 2012. Those pipeline segments potentially facing the greatest risks of failure from leaks or ruptures are to be assessed first. As of December 2005 (latest data available), 447 gas pipeline operators reported to PHMSA that about 20,000 miles of their pipelines (about 7 percent of all gas transmission pipeline miles) lie in highly populated or frequently used areas. Individual operators reported that they have as many as about 1,600 miles and as few as 0.02 miles of pipeline in these areas.

The 2002 act also requires that operators reassess these pipeline segments for safety threats at least every 7 years. Under flexibility provided by the act, PHMSA requires that operators reassess these pipeline segments for corrosion damage at least every 7 years in its implementing regulations, because corrosion is the most frequent cause of failures that can occur over time.[7] (See fig. 1.) PHMSA's regulations also incorporated, as mandatory, voluntary industry consensus standards on maximum reassessment intervals into these regulations for other types of safety threats. The industry standards require that operators reassess gas pipelines at least every 10, 15, or 20 years for all safety threats depending primarily on the condition of the pipelines and the pressure under which they operate. If conditions warrant, reassessments must occur more frequently. In addition, operators must perform prevention and mitigation activities—such as monitoring their pipelines for excavation or corrosion damage—on a continuing basis.

[7]Other types of failures are independent of time, such as damage from cold weather, land movement, or incorrect operation.

Figure 1: Reassessments Every 7 Years for Corrosion Supplement Broader Periodic Reassessments



Source: GAO.

Note: Periodic reassessments occur at least every 10, 15, or 20 years. Both periodic and 7-year reassessments are supposed to occur more frequently if conditions warrant.

Gas Integrity Management Program Benefits Pipeline Safety

Operators are making good progress in assessing and repairing their pipelines, thereby improving the safety of their pipeline systems. As of December 2005, operators had assessed about 6,700 miles of their 20,000 miles—or about 33 percent—of pipelines located in highly populated or frequently used areas. This progress indicates that they are well on their way to meeting the requirement to conduct baseline assessments on 50 percent of their pipelines in these areas by December 2007. In addition to assessing their pipelines, operators are also making progress in fulfilling the requirement to repair problems found on their pipelines in highly populated or frequently used areas. In the 2 years that operators have reported the results of integrity management, they have completed 340 repairs that were immediately required and another 1,981 scheduled repairs in highly populated or frequently used areas.[8] 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. Furthermore, the benefits of integrity management expand beyond highly populated or frequently used areas because a large number of operators are using internal inspection tools to assess their pipelines. These tools must be inserted and removed from the

[8]A repair must be made immediately when specific conditions are identified related to the strength of a pipeline such as, a dent with an indication of metal loss or cracking, or an anomaly judged to require immediate action. Scheduled repairs must be made within 1 year and generally include conditions where a dent has been identified but there is no indication of metal loss.

pipelines at designated locations that often run through other areas. Consequently, operators reported having assessed about 44,000 miles of pipelines located outside highly populated or frequently used areas, representing about 15 percent of all gas transmission pipelines. While operators are not required to report to PHMSA the results of these expanded assessments, operators we spoke with said that they plan to make necessary repairs identified through the assessments regardless of where they are identified.

We estimate that the integrity management program should offer additional safety benefits over the minimum safety standards for up to 68 percent of the population living close to gas transmission pipelines. This estimate corresponds with PHMSA's estimate of two-thirds of the population.

A number of representatives from pipeline industry organizations, state pipeline agencies, safety advocate groups, and operators that we contacted agree that integrity management benefits public safety because it requires all operators to systematically assess their pipelines to gain a comprehensive knowledge about the risks to their pipeline systems. Other benefits cited by operators include improved communications within their companies and more strategic resource allocation.

While the operators we contacted generally believe integrity management is beneficial, the program is not without its costs. For example, over half of the operators we spoke with said that they have hired additional staff or contractors as a result of the integrity management requirements. In addition, 19 of the operators we contacted (37 percent) were concerned 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. The regulations provide operators the flexibility to develop their programs to best suit their companies' needs, but each operator must develop and document specific policies and procedures to demonstrate its commitment to compliance with and implementation of the integrity management program. Operators may use existing policies and procedures if they meet the requirements of integrity management. In addition, an operator must document any decisions made related to integrity management to demonstrate that it understands the threats to their pipelines and is systematically managing their pipelines for these threats. While the operators we contacted generally 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. In addition, a few operators expressed concern that they will not know if they have sufficient documentation until their programs have been inspected. Initial inspections of operators by PHMSA and state pipeline agencies have confirmed that some operators are experiencing difficulty with documentation but are generally doing well with assessments and repairs. According to PHMSA and state officials, as operators continue to develop and implement their integrity management programs and as they are provided feedback during inspections, the documentation issues identified during these initial inspections should be resolved.

Another concern raised by 33 (65 percent) of the operators is the requirement to reassess their pipelines for corrosion problems at least every 7 years. This issue is discussed in the following section.

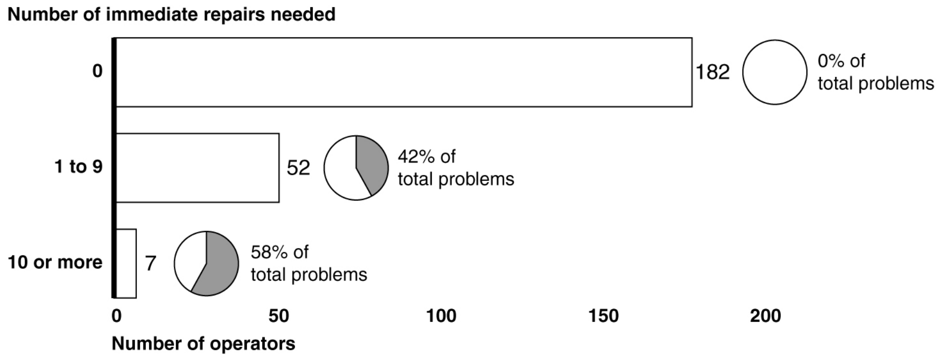
The 7-year Reassessment Requirement Appears to be Conservative

Periodic reassessments of pipeline threats are beneficial because threats—such as the corrosive nature of the gas being transported—can change over time. However, the findings from baseline assessments conducted to date and the generally safe condition of gas transmission pipelines leads us to conclude that the 7-year requirement appears to be conservative. Through December 2005 (latest data available), 76 percent of the operators (182 of 241) reporting baseline assessment activity to PHMSA told the agency that their pipelines were in good condition, free of major defects, and requiring only minor repairs.[9] (See fig. 2.) The remaining 59 operators found 340 problems requiring immediate repairs. About 60 percent of these problems occurred in seven operators' pipelines. Since PHMSA does not require that operators tell it the nature of the problems found, we do not know how many, if any, were due to corrosion. These assessments covered about 6,700 miles, or about one-third of the nationwide total to be assessed.[10]

[9]We contacted 52 operators about the results of their baseline assessments, and the results were largely consistent with the overall data reported to PHMSA.

[10]Another way to assess progress in completing baseline assessments and the effect of problems found would be to measure gas flows or pipeline capacity in those areas. This information is not readily available.

Figure 2: Most Operators Reported That Their Pipelines Are In Good Condition, as of December 2005



Source: GAO presentation of PHMSA data.

Note: Results of 241 operators that reported to PHMSA that they completed 6,700 miles of baseline assessments. Of those operators that reported no problems, 82 operate smaller pipeline systems (1-49 miles), 41 operate mid-sized pipeline systems (50-199 miles), and 59 operate larger pipeline systems (200 or more miles).

It is encouraging that the majority of operators nationwide reported that they found few or no problems requiring immediate repairs, because operators are supposed to assess pipeline segments facing the greatest risk of failure from leaks or ruptures first, as required by the 2002 act. In addition, since operators are required to identify and repair significant problems, the overall safety and condition of the pipeline system should be enhanced before reassessments begin toward the end of the decade.

Regarding the industry's overall safety record, over the past 5-1/2 years (from January 2001 through early July 2006), there were 143 corrosion-related incidents over the 295,000-mile transmission system (26 per year, on average)—none of which resulted in death or injury. Over the past 10-1/2 years, 12 people have died and 3 have been injured in two corrosion-related incidents.[11] Neither of these incidents occurred in a highly populated or frequently used area.

About 80 percent of the 52 operators that we contacted prefer that reassessment intervals be based on the condition and characteristics of

[11]All the fatalities and all but one of the injuries occurred in one incident. Over the same period, an average of 3 people have died and 8 people have been injured per year from all causes of natural gas transmission pipeline incidents.

the pipeline segment rather than on a prescriptive standard. About half of these operators (28) expressed a preference for the industry consensus standard developed by the American Society of Mechanical Engineers (ASME B31.8S-2004) for setting reassessment intervals for time-dependent threats because it incorporates a risk-based approach (for pipeline failure) and is based on science and engineering knowledge. This standard sets reassessment intervals at a maximum of 10 years for high-stress pipeline segments, 15 years for medium-stress segments, and 20 years for low-stress segments.[12] Maximum reassessment intervals, such as those in the industry consensus standard, incorporate such risk concepts as built-in safety factors (e.g., wall stress, test pressure, or predicted failure), conditions, and potential consequences of a pipeline incident on a segment-by-segment basis. The maximum intervals of 10, 15, and 20 years are based on worst-case corrosion growth rates.

Industry consensus standards allow for maximum reassessment intervals for time-dependent threats of 10, 15, or 20 years only if the operator can adequately demonstrate that corrosion will not become a threat within the chosen time interval. If not, then the reassessment must occur sooner, perhaps at 7 or even 5 or fewer years. Furthermore, according to industry consensus standards, it typically takes longer than the 10, 15, or 20 years specified in the standard for corrosion problems to result in a leak or rupture.

The industry consensus standards were developed in 2001 and updated in 2004 based on, among other things, the experience and expertise of engineers, contractors, operators, local distribution companies, and pipeline manufacturers; more than 20 technical studies conducted by the Gas Technology Institute, ranging from pipeline design factors to natural gas pipeline risk management; and other industry consensus standards including the National Association of Corrosion Engineers standards, on topics such as corrosion. Contributors have been practicing aspects of risk-based assessments successfully for over 10 years. The ASME standard serves as a foundation for nearly every section of PHMSA's integrity management regulations. The ASME standard was reviewed by the American National Standards Institute.[13] The Institute found that the

[12]Stress is measured in terms of operating pressure in relation to wall strength.

[13]The American National Standards Institute is 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.

standard was developed in an environment of openness, balance, consensus, and due process and therefore approved it as an American National Standard.

While the mechanical engineering standards are voluntary for the industry, PHMSA incorporated them as mandatory in its gas transmission integrity management regulations. The mechanical engineering society's standard for setting reassessment intervals is not the only industry consensus standard in PHMSA's integrity management regulations. The regulations incorporate other industry consensus standards for assessing corrosion threats and for determining temporary reductions in operating pressure. In addition, it is federal policy to encourage the use of industry consensus standards: Congress expressed a preference for technical standards developed by consensus bodies over agency-unique standards in the National Technology Transfer and Advancement Act of 1995. The Office of Management and Budget's Circular A-119 provides guidance to federal agencies on the use of voluntary consensus standards, including the attributes that define such standards.

Of the 52 operators we contacted, 44 had undertaken baseline assessments, and 23 of these have calculated their own reassessment intervals.[14] Twenty of these 23 operators indicated that, based on the conditions they identified during their baseline assessments, they would reassess their pipelines at maximum intervals of 10, 15, or 20 years—as allowed by industry consensus standards—if the 7-year reassessment requirement were not in place. The remaining three operators told us that they would reassess their pipelines at intervals shorter than the industry consensus standards but longer than 7 years because of the condition of their pipelines. These results add weight to our assessment that the 7-year requirement appears to be conservative for most pipelines.

Safeguards Exist if an Alternative Standard for Corrosion Reassessments is Allowed

PHMSA and the state pipeline agencies plan to inspect all operators' compliance with integrity management reassessment requirements, among other things, to ensure that operators continually and appropriately assess the conditions of their pipeline segments in highly populated or frequently used areas. These inspections should serve as a check as to whether

[14]The other 21 operators either (1) have not yet calculated reassessment intervals; (2) do not intend to, given prescriptive federal (7 years) or state (5 years in Texas) reassessment requirements; or (3) did not supply us with information on their reassessment intervals.

operators have identified threats facing these pipeline segments and determined appropriate reassessment intervals. PHMSA and states have begun inspections and expect to complete most of the first round of inspections no later than 2009. As of June 2006, PHMSA has completed 20 of about 100 inspections and, as of January 2006, states have begun or completed about 117 of about 670 inspections. Initial results from these inspections show that operators are doing well in assessing their pipelines and making repairs, but, as discussed earlier, some need to better document their programs. Based on the initial inspection results to date, PHMSA and states did not find many issues that warranted enforcement actions.

Finally, it is important to note that, in addition to periodic reassessments, operators must perform prevention and mitigation activities on a continuing basis. PHMSA regulations require that all operators of pipelines, including those outside highly populated or frequently used areas, patrol their pipelines for excavation and other damage, survey for leakage, maintain valves, ensure that corrosion-preventing protections are working properly, and take other prevention and mitigation measures.

(Attachment I summarizes results of our work to date on the expected availability of resources for pipeline reassessments and the likely impact of assessment activity (including reassessments) on the nation's natural gas supply. We will discuss these topics in more detail in when we report on the 7-year reassessment requirement this fall.)

Increasing State Funding Appears Reasonable, but Funding Sources and Oversight Plans Would Need To Be Addressed

The Subcommittee's draft bill proposes to increase the matching funds that PHMSA provides to states for pipeline safety program activities from a maximum of 50 percent to a maximum of 80 percent of a state's pipeline safety program costs. The increased funding would offset states' increased workload, such as activities related to gas transmission integrity management and other provisions in the 2002 act. All three legislative proposals also contain provisions, such as damage prevention programs, that could increase states' workloads. Furthermore, state pipeline safety activities would increase if PHMSA implements its planned integrity management program for distribution pipelines. Our recent survey to state pipeline safety agencies about their integrity management oversight programs showed that 39 of 47 state agencies are experiencing challenges in staffing, which could require increased funding. For example, two state officials told us that state agencies are losing trained inspectors because the state salaries are typically lower than what operators pay. PHMSA proposes to implement the increased funding in 5 percent increments over a 6-year period starting in fiscal year 2008.

We believe that the proposed increase in state grants to offset expanded state activities appears reasonable, provided that appropriate funding sources are identified and that the activities are included in PHMSA's oversight of state pipeline safety programs. According to PHMSA, the agency has several options for increasing funding for state grants, but has not developed a specific plan for how to provide additional funds. One option is for PHMSA to reprioritize its budget to channel additional funds from other activities, such as research, to states. Another option may be to increase user fees that are charged to pipeline companies. User fee assessments in fiscal year 2006 were about $150 per pipeline mile for natural gas transmission operators and about $76 per pipeline mile for hazardous liquid pipelines. All of these options involve tradeoffs among PHMSA's pipeline safety oversight activities or could result in increased fees from the pipeline industry. Therefore, the effects of these options would need to be carefully analyzed in order to find a balanced solution.

According to PHMSA, the agency plans to monitor increased state pipeline safety activities through its current oversight approach, which consists of reviewing annual reports from states and field evaluations of state activities. States are required to submit documentation annually about their pipeline safety program activities for the previous year, including information on the state's pipeline operators, inspections conducted, and enforcement of pipeline regulations. States are also required to submit a description of all ongoing and planned activities and an estimate of the total expenses for the next calendar year. PHMSA validates the information submitted by each state and attends at least one state inspection during field evaluations. As state pipeline safety activities expand, PHMSA would need to determine the best approach for including the new activities in its oversight of state pipeline safety programs.

Concluding Observations

The overall integrity management framework laid out in the Pipeline Safety Improvement Act is improving the safety of gas transmission pipelines. We have not identified issues that bring into question the basic framework of integrity management. Overall, we believe that PHMSA has done a good job in implementing the act. While we expect to make several recommendations to PHMSA when we complete our work, they will be aimed at incremental improvements, rather than major restructuring. Finally, regarding the 7-year reassessment requirement, our preliminary view is that these reassessment intervals should be based on technical data, risk factors, and engineering analyses rather than a prescribed term. We expect to make a recommendation to the Congress that the 2002 act be amended along these lines when we report on this issue. We expect to report to this Subcommittee and to other committees both on PHMSA's implementation of integrity management and the 7-year reassessment requirement in September.

GAO Contact and Staff Acknowledgements

For further information on this statement, please contact Katherine Siggerud at (202) 512-2834 or siggerudk@gao.gov. Individuals making key contributions to this statement were Jennifer Clayborne, Anne Dilger, Seth Dykes, Maria Edelstein, Heather Frevert, Bert Japikse, Timothy Guinane, Matthew LaTour, James Ratzenberger, and Sara Vermillion.

Appendix: Availability of Resources to Conduct Reassessments and Possible Impacts on the Nation's Natural Gas Supply

This appendix summarizes results of our work to date on the expected availability of resources for pipeline reassessments and the likely impact of assessment activity (including reassessments) on the nation's natural gas supply.

Sufficient Resources May Be Available for Pipeline Reassessments

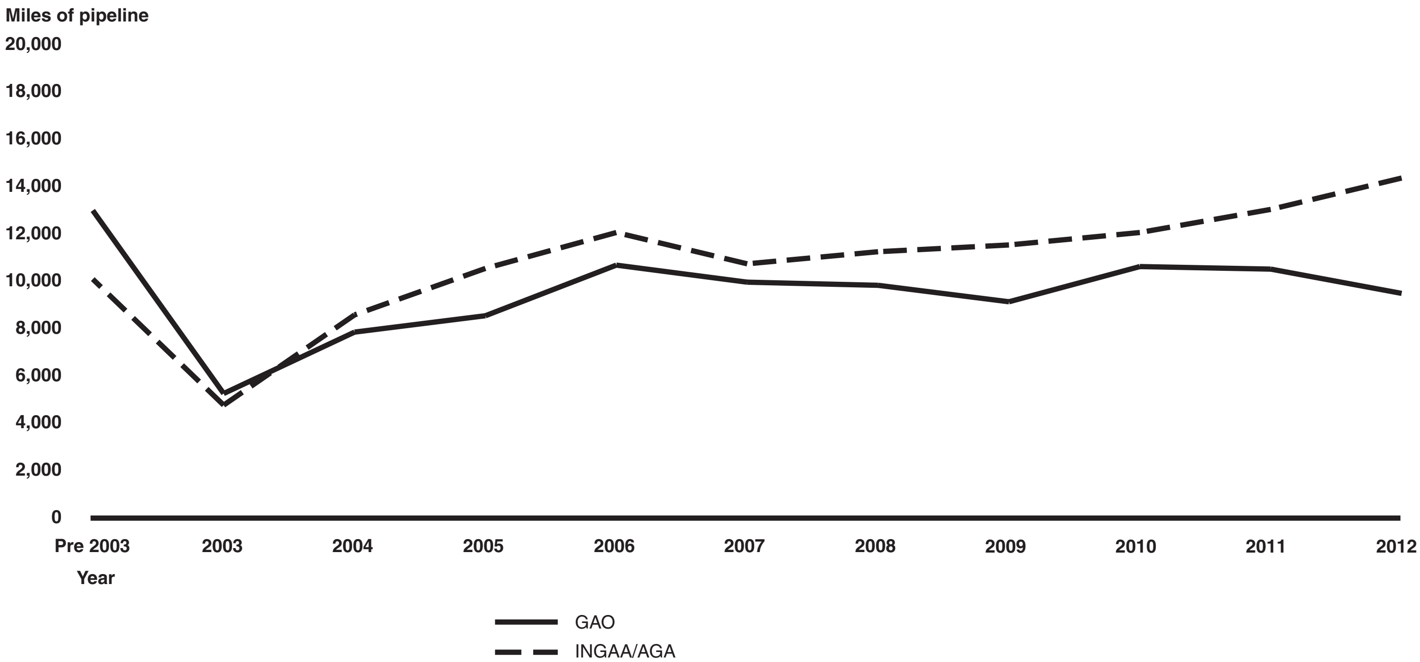
Sufficient resources may be available for operators to reassess their pipelines, but some uncertainty exists. Thirty-seven of the 52 operators, an in-line inspection association and four inspection contractors that we contacted told us that services and tools needed to conduct assessments will likely be available for baseline assessments and they do not anticipate difficulties obtaining these resources in the future. Operators that reported both baseline and reassessment schedules told us they plan to reassess 42 percent of their pipeline miles in highly populated or frequently used areas using in-line inspection.[1] An in-line inspection association and two contractors we contacted said that the in-line inspection industry is well established and has the capacity to expand readily. Operators plan to use direct assessment or confirmatory direct assessment methods in reassessing another 54 percent of their pipeline miles.[2] However, they told us that expertise for direct assessment methods is limited; therefore, they may not be as readily available to all operators.

The Interstate Natural Gas Association of America (INGAA), the American Gas Association (AGA) and we asked operators to estimate the number of miles of pipeline they planned to assess through 2012 in order to determine whether an increase in overall assessment activity would occur because of the overlap between completing baseline assessments and beginning reassessments from 2010 through 2012. The results were conflicting: the industry effort showed an increase in activity, while ours showed a decrease. (See fig. 3.) The reasons for these contrasting findings are unclear but may be due, in part, to the difference in methods used in collecting this information.

[1] In-line inspection involves running a specialized tool through a pipeline to detect and record anomalies, such as metal loss and damage.

[2] Direct assessment and confirmatory direct assessment involve using above-ground detection instruments, and then excavating suspected problem areas.

Figure 3: GAO and INGAA/AGA Results Show Different Trends in their Required Assessment Activity During the Overlap Period



Sources: GAO discussions with 52 operators and GAO analysis of INGAA/AGA results.

Impact of Periodic Reassessments on Natural Gas Supply May be Less than Foreseen

As the Pipeline Safety Improvement Act of 2002 was being considered, INGAA analyzed the possible impact of requiring assessments and periodic reassessments and found that significant disruptions in the natural gas supply and considerable price increases could occur.[3] A more moderate impact was predicted in three subsequent analyses—two reviews of the INGAA study performed for PHMSA by the John A. Volpe National Transportation Systems Center and by the Department of Energy during the congressional debate over the pipeline bill, and a post-act PHMSA

[3]Prepared for The INGAA Foundation, Inc., by Energy and Environmental Analysis, Inc., *Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas*, 2002.

evaluation of its implementing regulations.[4] A waiver provision was included in the 2002 act after INGAA's study was completed; this may serve as a safety valve if it appears that the natural gas supply may be disrupted. Finally, of the 44 natural gas pipeline operators that we contacted that had begun baseline assessments,[5] 26 operators (59 percent) indicated that their assessments and repairs did not require them to shutdown their pipelines or reduce their operating pressure. Sixteen (36 percent) reported minor disruptions in their gas supply because they temporarily shut down pipelines and reduced operating pressure to conduct assessments or repairs. They told us that they used alternate gas sources, such as liquefied natural gas, to sustain their customers' gas supply. The remaining two operators told us that they were not able to meet all their customers' needs, but the customers were able to obtain natural gas from other sources.

[4]See, Department of Transportation docket, RSPA-00-7666, *Energy Impact Statement for Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)*, March 28, 2002, prepared by John A. Volpe National Transportation Systems Center and the U.S. Department of Transportation; Comments from U.S. Department of Energy on INGAA's *Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas*, April 2, 2002; and Research and Special Programs Administration, *Final Regulatory Evaluation*, *Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)*, March 28, 2002.

[5]Fifty of the 52 operators that we contacted operate natural gas pipeline and six have not yet begun baseline assessment activities.

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