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Report to Congressional Committees

September 2006

NATURAL GAS PIPELINE SAFETY

Integrity Management Benefits Public Safety, but Consistency of Performance Measures Should Be Improved

GAO

Accountability ★ Integrity ★ Reliability

GAO-06-946

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Highlights

Highlights of GAO-06-946, a report to congressional committees

Why GAO Did This Study

The Pipeline Safety Improvement Act of 2002 established a risk-based program for gas transmission pipelines—the integrity management program. The program requires operators of natural and other gas transmission pipelines to identify "high consequence areas" where pipeline incidents would most severely affect public safety, such as those occurring in highly populated or frequented areas. Operators must assess pipelines in these areas for safety risks and repair or replace any defective segments. Operators must also submit data on performance measures to the Pipeline and Hazardous Materials Safety Administration (PHMSA).

The 2002 act also directed GAO to assess this program's effects on public safety. Accordingly, we examined (1) the effect on public safety of the integrity management program and (2) PHMSA and state pipeline agencies' plans to oversee operators' implementation of program requirements. To fulfill these objectives, GAO interviewed 51 gas pipeline operators and surveyed all state pipeline agencies.

What GAO Recommends

GAO recommends revisions to PHMSA's performance measures to improve the agency's ability to determine the impact of the program over time. The Department of Transportation generally agreed with the report's findings and recommendations.

www.gao.gov/cgi-bin/getrpt?GAO-06-946.

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.

September 2006

GAS PIPELINE SAFETY

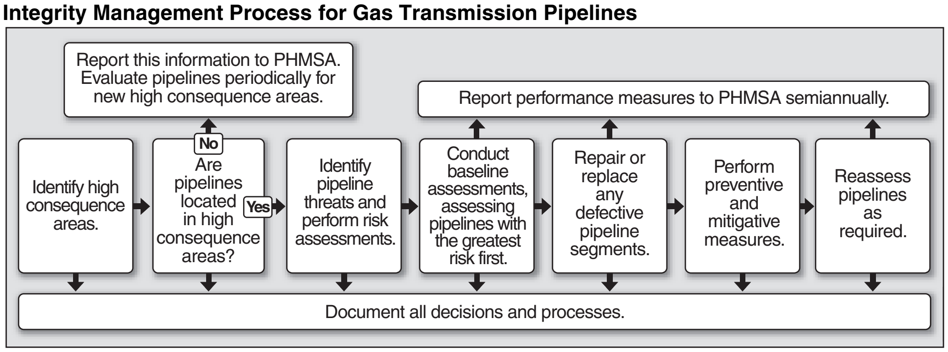
Integrity Management Benefits Public Safety, but Consistency of Performance Measures Should Be Improved

What GAO Found

The gas integrity management program is designed to benefit public safety by supplementing existing safety requirements with risk-based management principles that focus on safety risks in high consequence areas, such as highly populated or frequented areas. Early indications show that the condition of transmission pipelines is improving as operators complete assessments and related repairs of their pipelines. For example, as of December 31, 2005, operators had assessed 33 percent of pipelines in high consequence areas and completed over 2,000 repairs. Furthermore, up to 68 percent of the population living near gas transmission pipelines is expected to benefit from improved pipeline safety because they live in highly populated areas. Representatives from the pipeline industry, safety advocacy groups, and state pipeline safety agencies generally agree that integrity management improves public safety, but operators noted that the program can be costly to implement and cited concerns with implementing the program, such as meeting the documentation requirements. PHMSA's performance measures should demonstrate the impact of the program over time. However, we are recommending revisions to improve the measures. For example, adjusting the incident reporting requirement to account for changes in the price of natural gas would allow PHMSA to more accurately track trends in pipeline incidents.

PHMSA and states plan to use a variety of inspection tools to oversee operators' implementation of integrity management requirements and expect to complete the first round of inspections no later than 2009. To assist in conducting these inspections, PHMSA has developed a range of tools, including guidance documents and training courses for inspectors. Overall, state agencies have found these tools to be useful, although some states have found it difficult to schedule the required training courses and have some concerns about the adequacy of their staffing. To address these concerns, PHMSA is taking steps to make it easier for state inspectors to attend the training and supports providing additional funding to states. Initial results from 20 federal inspections and 117 state inspections show that operators are making good progress in assessing pipelines and making repairs, but they generally need to better document their decisions and processes.

Integrity Management Process for Gas Transmission Pipelines



Source: GAO.

Contents

Abbreviations

DOT	Department of Transportation
IMP	gas integrity management program
OPS	Office of Pipeline Safety
PHMSA	Pipeline and Hazardous Materials Safety Administration

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Washington, D.C. 20548

September 8, 2006

Congressional Committees:

While pipelines are a relatively safe mode for transporting natural gas, on average, about three people have died and about eight people have been injured annually over the past 10 years in natural gas transmission pipeline incidents. To enhance the safety of pipelines and strengthen existing federal pipeline safety oversight by the Pipeline and Hazardous Materials Safety Administration (PHMSA), Congress passed the Pipeline Safety Improvement Act of 2002. A key element of the act is a risk-based program—termed “integrity management”—for gas transmission pipelines. The integrity management program requires gas transmission pipeline operators (operators) to develop programs to assess and mitigate safety threats to sections of their pipeline systems where leaks or ruptures would have the greatest impact on public safety. These “high consequence areas” are generally in highly populated or frequently used areas, such as parks. Operators must identify their pipelines in high consequence areas and then systematically assess these pipelines for safety risks, such as internal corrosion, and repair or replace any defective pipeline sections. Operators must also take additional measures, such as computer monitoring of the pipeline and additional training on response procedures, to prevent and mitigate the consequences of a pipeline failure in high consequence areas.

The Pipeline Safety Improvement Act of 2002 directed us to assess the effects on public safety stemming from the integrity management program for gas transmission pipelines. Accordingly, we examined (1) the effect on public safety of the integrity management requirements for gas transmission pipelines and (2) the plans of PHMSA and state pipeline safety agencies to oversee operators’ implementation of integrity management requirements.

To carry out this work, we reviewed laws, regulations, and PHMSA guidance and inspection reports related to the gas integrity management program. We interviewed agency officials responsible for developing and administering the gas integrity management program, gas pipeline trade associations, pipeline safety advocacy groups, state pipeline agencies, and

51 gas transmission pipeline operators.[1] The information that we obtained from the operators is not generalizable to all operators. We also surveyed the 47 state pipeline agencies with responsibility for overseeing gas transmission pipeline operators' implementation of integrity management.[2] As part of our work, we assessed the internal controls and the reliability of the data needed for this engagement and determined that the data were sufficiently reliable for our purposes. We performed our work between August 2005 and July 2006 in accordance with generally accepted government auditing standards. (See app. I for additional details on our scope and methodology and app. II for a copy of our survey sent to state pipeline agencies and the aggregated results.)

Results in Brief

The gas integrity management program is benefiting public safety by supplementing existing safety requirements with risk-based management principles that focus on safety risks in highly populated or frequented areas, referred to as high consequence areas. While the program is still being implemented, the condition of transmission pipelines is improving as operators complete their first round of pipeline assessments and make repairs. As a result of integrity management, 33 percent of the identified pipelines in high consequence areas had been assessed and over 2,000 repairs had been completed, as of December 31, 2005. Furthermore, 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. Gas pipeline industry, state pipeline agency, and safety advocate representatives generally agree that the program enhances public safety, citing operators' improved knowledge of the risks to their pipeline systems that stems from systematic assessments as the primary benefit of the program. However, operators noted that integrity management is not without its costs; most operators we contacted have hired additional staff or contractors as a result of integrity management requirements.

[1] 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. Therefore, our work focused on natural gas pipelines.

[2] Pipeline agencies in 46 states and the District of Columbia have this responsibility and, for the purposes of this report, we treat the agency in the District of Columbia as a state pipeline agency. Two states do not have state pipeline agencies, and two states do not have any intrastate gas transmission operators.

Furthermore, operators cited concerns about implementing the program, such as meeting the program's documentation requirements. Despite these concerns, operators are making good progress in assessing and repairing their pipeline systems, as demonstrated by the semiannual performance measures that operators report to PHMSA. However, how the performance measures are reported may hinder PHMSA's ability to determine the program's impact over time. For example, incident reporting requirements do not include an adjustment for changes in the price of natural gas, even though the value of gas released is a key factor in determining whether an incident should be reported to PHMSA. Therefore, a change in the number of incidents reported over time may reflect a change in the price of natural gas rather than a change in the safety of the pipeline system. We are making recommendations to improve the performance measures, thereby improving PHMSA's ability to assess the effectiveness of the integrity management program.

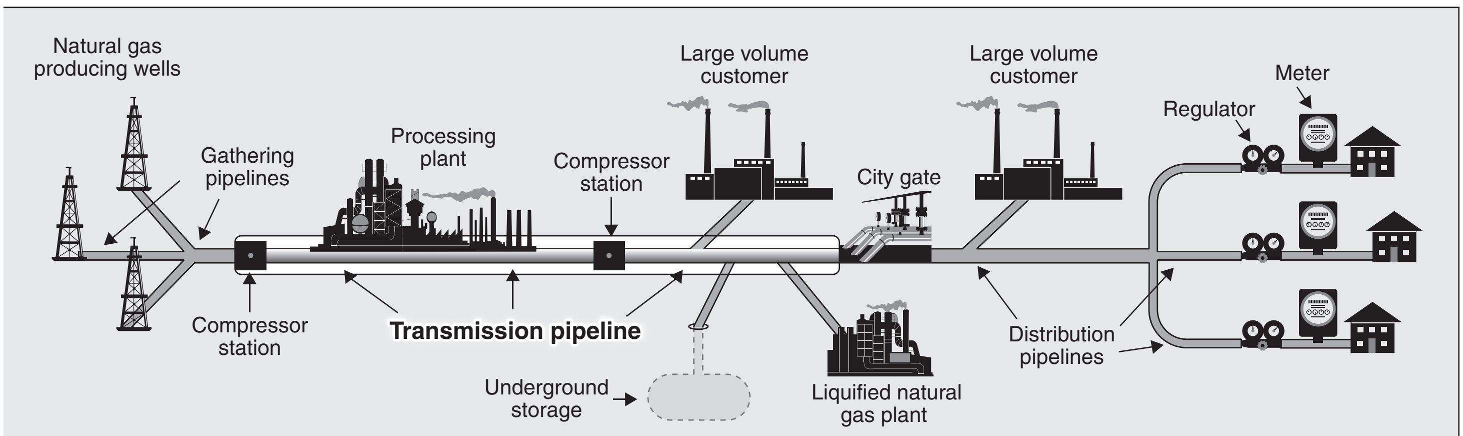
PHMSA and states plan to use a variety of inspection tools to oversee operators' implementation of integrity management requirements and expect to complete the first round of inspections no later than 2009. PHMSA developed a range of tools to help prepare and assist federal and state inspectors in conducting integrity management inspections, including guidance documents for evaluating operators' integrity management programs, training courses to provide inspectors with a knowledge of technical issues, and communication mechanisms. Overall, state agencies have found these tools to be useful, although several states have found it difficult to schedule the required training courses, and many have expressed concerns about the adequacy of their staffing. To address these concerns, PHMSA has taken steps to make it easier for state inspectors to attend the training, and it supports providing additional funding to states that could be used for staffing needs. PHMSA and states have begun inspections. According to PHMSA and state officials, initial results from 20 of about 100 federal inspections and 117 of about 670 state inspections that have been completed or started show that operators are doing well in assessing their pipelines and making repairs; but, in general, operators need to better document their policies and procedures. Based on these initial inspection results, PHMSA and states generally did not find many issues that warranted enforcement actions to date.

In commenting on a draft of this report, the Department of Transportation generally agreed with the report's findings and recommendations and cited actions the department has already initiated or plans to take to implement the recommendations.

Background

Within the United States, there are about 295,000 miles of gas transmission pipelines, which are part of larger gas pipeline systems that transport natural gas from producing wells to users. (See fig. 1.) Gas gathering lines collect natural gas from production facilities and transport it to transmission pipelines. In turn, gas transmission pipelines transport gas products to processing plants, and then on to communities and large-volume users, such as power plants. Gas distribution pipelines continue to transport natural gas from transmission pipelines to residential, commercial, and industrial customers.

Figure 1: Gas Pipeline System



Source: Pipeline and Hazardous Materials Safety Administration.

PHMSA, within the Department of Transportation (DOT), administers the national regulatory program to ensure the safe transportation of natural gas and hazardous liquid by pipeline.[3] PHMSA carries out its mission through regulation, national consensus standards, research, education, inspections, and enforcement when safety problems are found. The agency 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. In general, PHMSA retains full responsibility for inspecting and enforcing

[3]In addition to the gas gathering and transmission pipelines, PHMSA oversees the safety of nearly 1.9 million miles of gas distribution pipelines and 160,000 miles of hazardous liquid pipelines.

regulations on interstate pipelines that cross state boundaries, but it has arrangements with 48 states, the District of Columbia, and Puerto Rico to assist with overseeing intrastate pipelines. PHMSA allows state agencies the flexibility to design their programs to best meet their needs, although it conducts an annual audit of each state's inspection program. 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 performed its oversight role using uniform, minimum safety standards that all pipeline operators must meet.[4] For gas transmission pipeline operators, these standards are 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 thickness of the pipe required and the pressure at which it can operate. Recognizing that pipeline operators face different risks, depending on such factors as location and the products they carry, PHMSA began exploring the concept of a risk-based approach to pipeline safety in the mid-1990s.[5] The Accountable Pipeline Safety and Partnership Act of 1996 included provisions for DOT to establish a demonstration program to test such a risk-based approach.[6] As a result, PHMSA established the Risk Management Demonstration Program, which went beyond the agency's traditional regulatory approach by allowing individual operators to identify and focus on the risks unique to their pipelines. According to a PHMSA official, the demonstration project identified the need for operators to better understand the condition of their pipelines, including the risks and threats to their pipelines. The agency subsequently moved forward with a new regulatory approach—termed integrity management—to supplement the existing uniform, minimum regulations. Integrity management created a systematic process to managing the safety of the pipeline and is designed to provide for continual improvement. PHMSA established requirements for integrity management for hazardous liquid pipeline operators with 500 or more miles of pipelines in December 2000 and for operators with less than 500 miles in January 2002. In 2000, PHMSA was also exploring issues

[4]Minimum safety standards for natural gas pipelines are found in 49 C.F.R. part 192; and safety standards for hazardous liquid pipelines are found in 49 C.F.R. part 195.

[5]Within PHMSA, the Office of Pipeline Safety administers the national regulatory program to assure the safety of pipelines. Prior to March 2005, PHMSA was known as the Research and Special Programs Administration.

[6]P.L. No. 104-304, 110 Stat. 3793 (1996).

related to integrity management for gas transmission pipelines, including collaboration with the pipeline industry to develop consensus standards for gas integrity management, which were subsequently incorporated into the regulations. These consensus standards cover issues such as establishing and conducting integrity management programs and actions operators must take to assess the extent of corrosion in their pipelines.

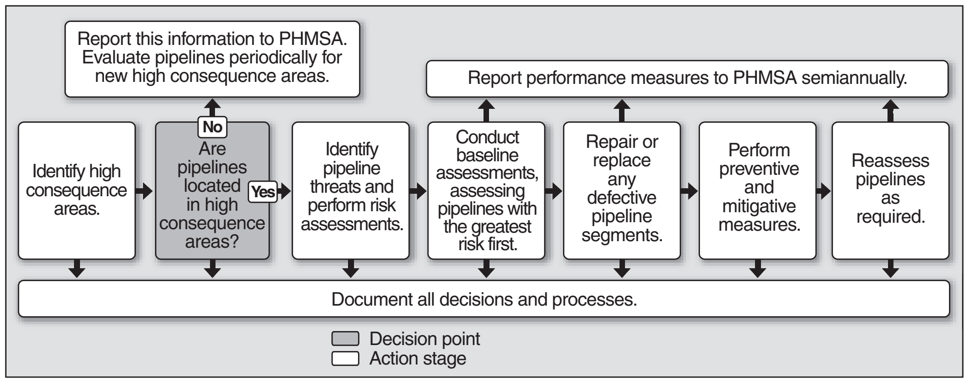
In 2003, PHMSA issued integrity management regulations for all operators of gas transmission pipelines.[7] As shown in figure 2, under these regulations, operators must identify and assess segments of their pipelines that are located in "high consequence areas," which are highly populated or frequently used areas, such as parks, where pipeline leaks or ruptures could have the greatest impact on public safety. Operators are required to collect and integrate data from their entire pipeline system—such as maps, information on corrosion protection, exposed pipeline, and threats from excavation or other third-party damage—to identify the threats to their high consequence areas. Pipeline threats include corrosion; welding defects and failures; third-party damage (e.g., from excavation equipment); land movement; and incorrect operation. Once operators have identified the threats, they must perform a risk assessment to determine which pipeline segments are most susceptible to those threats. Starting with the pipelines that are most susceptible, operators must then assess the condition of their pipelines—referred to as baseline assessments—on half of their pipeline mileage in high consequence areas by December 2007 and the remainder by December 2012. Using the results of the assessments, operators must repair or replace any defective sections of pipeline. Operators are also required to perform preventive and mitigative measures, such as installing computerized monitoring and leak detection systems.[8] In addition, operators are required to reassess their pipelines in high consequence areas for corrosion problems at least every 7 years and for all safety threats at least every 10, 15, or 20 years, depending on the condition of the pipelines and the stress under which the pipeline segments are operated. Operators must also document processes to ensure actions for managing pipeline integrity are applied consistently and that the results are repeatable across the company. For example, operators are required to

[7]PHMSA is currently developing integrity management regulations for gas distribution pipelines and expects to issue these regulations in 2007.

[8]The measures are in addition to those already required in 49 C.F.R. part 192 and are specific to the threats that were identified for each pipeline segment.

have written processes for management of change, quality assurance, and communication.

Figure 2: Integrity Management Process for Gas Transmission Pipelines



Source: GAO.

Gas Integrity Management Benefits Public Safety, although Operators Have Some Implementation Concerns, and Performance Measures Could Be Improved

The gas integrity management program is designed to improve pipeline safety by supplementing existing standard safety requirements with risk-based management principles, including performance measures to monitor progress. For the first time, all operators are required to systematically assess the condition of their pipelines in high consequence areas and make identified repairs. As of December 31, 2005, operators report having assessed about 33 percent of their pipelines in high consequence areas and completed over 2,000 repairs. In addition, we estimate that up to 68 percent of people living along natural gas transmission pipelines are located in highly populated areas and are expected to receive additional protection as operators continue to assess and repair their pipelines in these areas. Furthermore, the gas pipeline industry, state pipeline agencies, safety advocate representatives, and operators with whom we spoke generally agree that the program benefits public safety. While early indicators show that integrity management benefits public safety, some operators noted that the program is not without its costs. Operators also expressed uncertainty about the program's documentation requirements. Despite these concerns, operators are making good progress in implementing integrity management, as demonstrated by the performance measures that operators report semiannually to PHMSA. However, these performance measures could be improved to better enable PHMSA to identify the program's impact on public safety.

Integrity Management Offers Additional Protection Over Minimum Safety Standards

Prior to the integrity management program, there were, and still are, minimum safety standards for the design, construction, operation, and maintenance of all gas transmission pipelines that provide the public with a basic level of protection from pipeline failures. For example, all operators are required to have a system to protect their pipelines from corrosion. Federal or state inspectors use a "checklist" approach to determine whether operators have such a system and that it is operating appropriately.[9] However, the minimum safety standards do not account for the differences in the kinds of threats and degrees of risk that pipelines face. In addition, inspections of the operators verify that the standards are being followed, but do not evaluate the effectiveness of the protective measures put into place, such as the corrosion protection system, because the standards do not require operators to assess the integrity of their pipelines. Consequently, some pipelines have operated for 40 or more years without being assessed. However, 33 of 51 operators (about 65 percent) told us they had assessed the integrity of some of their pipelines prior to the integrity management regulations.

The gas integrity management program goes beyond existing minimum safety standards by using risk-based management principles to provide an additional level of safety to the public where the impact of pipeline leaks, failures, or incidents could be the greatest. Risk-based management has several key characteristics that help to ensure safety—it (1) uses information to identify and assess risks; (2) prioritizes risks so that resources may be allocated to address higher risks first; (3) promotes the use of regulations, policies, and procedures to provide consistency in decision making; and (4) monitors performance. The gas integrity management program embodies each of these characteristics. It requires operators to integrate information from different sources (both internal and external) to identify the risks specific to their pipelines and then use data from the assessment of their pipelines to make necessary repairs and take preventive measures. To prioritize risks for resource allocation, integrity management focuses on high consequence areas and requires operators to assess the riskiest segments of their pipelines first. Five operators told us that the requirements of integrity management has helped focus resources, and one said it has even helped to justify the need for resources that would otherwise have been difficult to obtain. To provide a

[9]According to guidance which PHMSA provided to the states, state inspectors may use an inspection form or checklist that references the federal and state regulations.

level of consistency in how tasks are performed and decisions are made, the integrity management program requires operators to document their policies and procedures. In addition, PHMSA developed inspection protocols and "frequently asked questions" to help define the agency's expectations for operators and help ensure consistency in inspections. According to PHMSA, having procedures, roles, and responsibilities clearly defined is crucial for operators to ensure continual and consistent management for safety. Finally, integrity management requires operators to monitor their progress by reassessing their pipelines at specified intervals. Operators must also report to PHMSA semiannually on specific performance measures related to integrity management. These measures include the total mileage of pipelines and the mileage of pipelines assessed in high consequence areas, as well as the number of repairs made and the number of incidents, leaks, and failures identified in these areas.

We estimate that this risk-based approach should offer additional safety benefits for up to 68 percent of the population living near gas transmission pipelines; this estimate corresponds with PHMSA's estimate of two-thirds of the population. Even though the integrity management program applies to only pipelines in high consequence areas, which account for about 7 percent of all transmission pipeline miles, the population living along pipelines tends to be clustered in these areas. Using Census data, we estimated that up to 68 percent of the people who live near (within 660 feet) natural gas transmission pipelines are located in highly populated areas and thus should be afforded additional protection as a result of integrity management. (See fig. 3.)

Figure 3: Highly Populated Areas within 660 Feet of a Natural Gas Transmission Pipeline

Sources: the U.S. Census Bureau and PHMSA (data); GAO (graphic).

While operators do not report the location of their high consequence areas, population is a key component to identifying these areas. Using Census data to identify the population living along pipelines, we estimated that about 22,000 miles of transmission pipelines could be considered as being in highly populated areas, which is similar to the 20,294 miles of pipelines reported by operators as being in high consequence areas. Therefore, our estimate of the highly populated areas is a reasonable approximation of the high consequence areas.

Early Indicators Show That Integrity Management Is Beneficial, Despite Some Operators' Concerns about Implementation

Although the integrity management program is still being implemented, a number of representatives from pipeline industry organizations, state pipeline agencies, safety advocate groups, and operators 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. In addition, operators must repair problems or anomalies identified in their pipelines. As of December 31, 2005, 33 percent of the identified pipelines in high consequence areas had been assessed, and over 2,000 repairs had been completed.

Six of the 51 operators we interviewed also pointed to the benefit of improved communications within their companies. Investigations of pipeline incidents have shown that, in some cases, an operator possessed information that could have prevented an incident but did not share the information with employees who needed it most. The integrity management program requires operators to integrate pipeline data from various sources within the company to identify threats to the pipelines, leading to more interaction among different departments within pipeline companies.

While all operators we contacted generally believe integrity management is beneficial, the program is not without its costs. For example, over half of the operators with whom we spoke said that they have hired additional staff or contractors as a result of integrity management requirements. Furthermore, one operator told us that, although it assessed its pipeline before the gas integrity management program was enacted, the operator now spends about 5,000 to 10,000 more hours per year on assessments because it must integrate data from multiple sources—some of which are formatted differently—requiring that the operator make all data consistent before using it. Another operator told us that implementation of the program was costly because its gas transmission pipelines are located under pavement. These pipelines could not be assessed using tools that run through pipelines, so the operator had to excavate, visually assess, and repave over the pipelines, which is costly. A third operator estimated that it had spent between $8.5 million and $10 million on developing its integrity management program and related systems. This operator also estimated that its annual operating costs had increased by $16.5 million to $21.5 million to comply with the integrity management regulations, even though it had an aggressive inspection and testing program prior to those regulations.

Operators also cited other concerns about implementing their integrity management programs. One of the more frequently identified concerns by the operators, cited by 19 of the 51 operators we contacted (37 percent), was related to 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 integrity management requirements. In addition, operators must document any integrity management related decisions to demonstrate that they understand the risks to their pipelines and are systematically managing their pipelines for these risks. For example, an operator must document how it identified the threats to its pipeline and assessed the risks, how these risks will be managed, who was involved in these decisions and their qualifications, and the data they used. 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 program has been inspected. Initial inspections of operators by PHMSA and state pipeline agencies have confirmed that some operators are experiencing difficulty with documentation but generally are 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 a majority of the operators is the requirement to reassess their pipelines for corrosion problems at least every 7 years. We recently reported that while reassessments are useful, the 7-year requirement appears to be conservative.[10]

[10]GAO, *Natural Gas Pipeline Safety: Risk-based Standards Should Allow Operators to Better Tailor Reassessments to Pipeline Threats*, GAO-06-945 (Washington, D.C.: Sept. 8, 2006).

Performance Measures Should Show Impact of Integrity Management Over Time, but Could Be Improved

Operators report to PHMSA semiannually on several performance measures that show the progress operators have made in implementing integrity management and, over time, should demonstrate the impact of integrity management on safety. Table 1 lists the performance measures and shows the progress operators reported as of December 31, 2005.

Table 1: Integrity Management Performance Measures Reported by Operators as of December 31, 2005

Pipeline performance measures for gas transmission pipelines	Statistics
Total miles of pipelines reported	296,138
Total miles of pipelines assessed	50,441
Gas transmission pipelines within high consequence areas:	
Total miles reported	20,294
Total miles assessed	6,707
Leaks[a]	221
Failures[b]	28
Incidents[c]	19
Immediate repairs completed[d]	340
Scheduled repairs completed[e]	1,981

Source: PHMSA.

[a]A leak is an unintentional escape of gas from a pipeline that does not result in an injury, death, or $50,000 in property damage.

[b]Failure is a general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use.

[c]An incident is defined as an event that involves a release of gas from a pipeline and (1) a death or personal injury necessitating in-patient hospitalization or (2) estimated property damage, including cost of gas lost, of $50,000 or more, or an event that is significant, in the judgment of the operator.

[d]An immediate repair must be made when specific conditions are identified related to the strength of a pipeline, a dent with an indication of metal loss or cracking, or an anomaly judged to require immediate action.

[e]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.

Total mileage reported and assessed: As a result of technology that many operators are using to assess their pipelines, operators are assessing a much greater portion of total pipeline mileage than that which is located in high consequence areas. In addition, they are making repairs to these pipelines. Of the 51 operators we contacted, 36 (71 percent) are using in-line assessment tools that run inside the pipelines to assess the integrity of some or all pipelines within high consequence areas. These tools must be inserted and removed from the pipelines at designated locations that often run through areas other than high consequence areas. Consequently, operators reported having assessed about 44,000 miles of pipelines located outside high consequence areas, which represents about 15 percent of all gas transmission pipelines. Operators that use the in-line assessment tools told us that they assess the entire distance of pipeline between the insertion and retrieval points because, in doing so, they gather additional insights into the condition of their pipeline. While operators are not required to report to PHMSA the results of the assessments in areas outside of the high consequence areas, a number of operators with whom we spoke said that they plan to make or have made repairs identified through the assessments, regardless of where they are identified, thereby expanding the benefits of integrity management beyond the high consequence areas.

High consequence mileage reported and assessed: As of December 2005, operators had assessed about 6,700 miles of their 20,000 miles of pipeline —or about 33 percent—located in high consequence areas. This progress indicates that operators 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. Operators must then complete the rest of their baseline assessments by December 2012. Most of the operators with whom we spoke (48 of 51) said they had no major concerns about their ability to complete baseline assessments, as required.

Incidents, leaks, and failures: While pipelines are considered a relatively safe mode of transporting gas, integrity management is designed to improve pipeline safety and should lead to a reduction in the number of incidents, leaks, and failures over time. PHMSA and the pipeline industry have generally used the number of incidents, related fatalities, and injuries as a measure for determining the safety of pipelines. Since the inception of integrity management, 19 of the 305 incidents reported for all pipelines in fiscal years 2004 and 2005 occurred in high consequence areas. The majority of the incidents reported in high consequence areas—10 of the 19 incidents—were caused by third-party damage. Leaks have traditionally been reported by operators in their annual reports, but this information is not generally aggregated nationwide, so it is not possible to determine how leaks in high consequence areas compare with those in other areas. Failures were not typically reported to PHMSA prior to integrity management; therefore, it is not possible to compare the number of failures in high consequence areas with those in other areas. As PHMSA collects information on incidents, leaks, and failures over time, the agency will be able to identify trends and make these comparisons.

Immediate and scheduled repairs completed: In addition to assessing pipelines, operators are also making progress in fulfilling the requirement to repair problems found on pipelines in high consequence 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 high consequence areas. While it is not possible to determine the number of needed repairs that 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 down the pipeline for immediate repair.

While the integrity management performance measures should allow PHMSA to measure the impact of the program, the measures related to incidents, leaks, and failures could be improved to better allow for optimal comparison of performance over time and make them more consistent with other pipeline safety measures. For example, incident reporting requirements do not include an adjustment for changes in the price of natural gas, even though the value of gas released is a key factor in determining whether an incident must be reported to PHMSA. A reportable incident is defined, in part, as when the estimated property damage, including the cost of gas lost, meets a threshold of $50,000. Since this reporting threshold has not been adjusted over time, as the price of gas has increased, it is difficult to use the number of incidents over time as an indicator of pipeline safety. For many years the price of gas was relatively stable. However, since 1999, natural gas prices have increased by about 179 percent, while the threshold for reporting an incident has not changed. As a result, smaller releases of gas from a pipeline meet the definition of an incident and artificially inflate the number of pipeline incidents. For example, in 1999, a release of about 16,100 thousand cubic feet of gas would have triggered the incident reporting requirement, compared with only about 5,800 thousand cubic feet of gas in 2005. In 2002, PHMSA began collecting information on the value of gas released during an incident. Adjusting the 183 gas transmission pipeline incidents that occurred in 2005 to reflect the price of gas in 1999 would have resulted in about 27 fewer incidents. PHMSA officials recognize the advantages of changing the reporting requirements to adjust for the changing price of gas or to be based on the volume of gas rather than its value, but PHMSA has not yet initiated a rule to change the reporting requirement.

In addition, the usefulness of the performance measure data is limited in part by inconsistencies in the reporting of causes of incidents and leaks in high consequence areas compared with the rest of the pipeline system. For example, to report a leak within a high consequence area, operators may choose from three separate corrosion causes: internal corrosion, external corrosion, or stress-corrosion cracking.[11] In contrast, to report a leak outside of a high consequence area, operators use one overall category for corrosion. Without consistent reporting of causes, it is difficult to compare the reasons for incidents and leaks in high consequence areas with those along the rest of the pipeline system. We are making recommendations to improve the consistency of the integrity management performance measures.

PHMSA and State Pipeline Agencies Plan to Use Inspection Tools Developed by PHMSA to Complete the Initial Round of Inspections by 2009

PHMSA has developed various tools to help prepare and assist federal and state inspectors in conducting inspections. These inspection tools include guidance documents for evaluating operators' integrity management programs, training courses to provide inspectors with the knowledge of technical issues, and communication mechanisms. Overall, most state pipeline agency officials told us that these tools are useful; although about half of the state officials with whom we spoke have found it difficult to schedule the required training courses, and the majority have some concerns about the adequacy of their staffing. To address these concerns, PHMSA has taken steps to make it easier for state inspectors to attend training and supports a proposal from states to provide additional funding that could be used for staffing needs. PHMSA and states have begun inspections and expect to complete the first round of inspections no later than 2009. PHMSA has completed 20 of about 100 inspections, and states have begun or completed 117 of about 670 inspections, as of June 2006 and January 2006, respectively. PHMSA and state officials reported that the initial results from these inspections show that operators are doing well in

[11]Internal corrosion occurs on the inside of the pipe due to a chemical attack from something in the pipe, external corrosion occurs on the outside of the pipe due to environmental conditions, and stress-corrosion cracking results from stress that causes clusters of cracks to develop and grow until the pipe fails.

implementing the assessment and repair requirements of the integrity management program, but they need to improve documentation of their program's processes.

PHMSA Has Developed Tools to Prepare Inspectors for Integrity Management Inspections

In collaboration with state pipeline agencies, PHMSA developed guidance documents—inspection protocols, supplemental guidance, and "frequently asked questions"—to assist federal and state inspectors in evaluating operators' integrity management programs. The inspection protocols provide a roadmap for conducting inspections. The protocols walk the inspectors through the integrity management requirements in the regulations to help inspectors verify that an operator's program complies with the regulations. These inspection protocols are available to the public, and many operators with whom we spoke said they had reviewed the protocols when developing their programs. To supplement the inspection protocols, PHMSA has provided inspectors with additional guidance on the types of questions to ask operators, documents to review, and key elements to consider in evaluating operators' programs. However, this supplemental guidance has not been provided to operators: it is intended to be suggestions for inspectors rather than requirements for operators because PHSMA expects programs to differ, given that each operator is unique. In addition, PHMSA posts "frequently asked questions" and corresponding answers to its Web site. This tool further clarifies the regulations and PHMSA's expectations for what should be included in operators' plans.

PHMSA also developed a series of required training courses to inform federal and state inspectors of technical topics relevant to the integrity management regulations. The 10 training courses—4 classroom and 6 computer-based courses—take about 20 days to complete and address the integrity management inspection protocols as well as specific threats to the pipelines (such as stress-corrosion cracking, and internal and external corrosion) and different assessment techniques (such as in-line assessment and direct assessment).[12] While most (13 of 21) state officials with whom we spoke consider the required training to be important, about half noted that it is difficult for inspectors to schedule the classroom training on inspection protocols. PHMSA has taken steps to help state inspectors

[12]In-line assessment involves running a specialized tool through a pipeline to detect and record problems, such as corrosion and damage. Direct assessment is a structured process to integrate information on the physical characteristics and operating history of a pipeline with the results of an examination to determine the integrity of the pipeline.

attend this training, such as offering the course in each of the five PHMSA regional offices in 2005 and providing travel funds for two inspectors from each state to attend. In addition, PHMSA maintains flexibility in scheduling the course and schedules classes once it receives enough requests. As a result, according to PHMSA records, at least one inspector from 46 of 47 states has attended the required training. The remaining state agency reported that it had confirmed that the gas transmission pipeline operators in its state do not have any pipelines in high consequence areas.

Another tool that PHMSA and state pipeline agencies may use is on-the-job training. PHMSA invites state inspectors to participate in PHMSA-led inspections of interstate operators that allow state inspectors to learn how PHMSA conducts inspections, to ask questions, and to gain experience in using the protocols. The majority (12 of 21) of state officials with whom we spoke indicated that their inspectors have, or will have, participated in PHMSA-led inspections before conducting their own inspections. As time permits, PHMSA inspectors also will attend state-led inspections to provide guidance and answer questions.

Finally, PHMSA has implemented several mechanisms—such as Web sites, conference calls, and meetings—to communicate with federal and state inspectors. For example, PHMSA created a restricted Web site where federal and state inspectors may obtain guidance documents, access information pertaining to inspections, pose questions on the integrity management program, and communicate with other inspectors. Through this tool, inspectors may learn from other inspectors' experiences by reviewing documentation of completed inspections that are posted. All completed federal inspections will be posted, and 28 states reported that they intend to post the results of their inspections as well. PHMSA also holds conference calls and periodic meetings with federal and state inspectors to discuss their experiences and identify opportunities to improve the inspection program. In addition, PHMSA keeps state pipeline agencies informed about gas integrity management through regular updates through the National Association of Pipeline Safety Representatives. These updates include Web site links and status reports on issues such as training classes, upcoming inspections, and work groups. Although communication between PHMSA and states has been problematic in the past, the majority of states (41 of 47) reported that

PHMSA's efforts to improve communication and guidance pertaining to gas integrity management have been useful.[13]

First Round of Inspections Is Expected to Be Completed by 2009 and Initial Inspections Show Operators Are Making Good Progress in Conducting Assessments

PHMSA and state pipeline agencies plan to conduct more than 700 gas integrity management inspections, with the majority expected to be completed no later than 2009.[14] PHMSA anticipates conducting a total of about 100 inspections of interstate gas transmission pipeline operators, of which about 80 are expected to have pipelines in high consequence areas. The 47 state pipeline agencies anticipate conducting a total of about 670 inspections of intrastate gas transmission operators, including those with and without pipelines in high consequence areas.[15] The majority of states (41 of 47) reported that they will each conduct fewer than 20 inspections, although one state reported that it will conduct as many as 256 inspections. Just as operators continually assess their pipelines, PHMSA and states plan to inspect operators' programs on a regular basis. PHMSA plans to conduct inspections of operators' programs at least once every 3 or 4 years, and more than half of the state agencies plan to conduct these inspections at least once every year or 2.

To conduct these inspections, PHMSA currently has 22 trained inspectors, 9 of which are assigned exclusively to conducting integrity management inspections. In 2002, we reported that PHMSA's efforts to identify the resources and expertise needed to implement its integrity management approach were hampered by the lack of an up-to-date assessment of current and future staffing and training needs.[16] In response to our recommendation to develop a workforce plan, PHMSA drafted a workforce

[13]GAO, *Pipeline Safety and Security: Improved Workforce Planning and Communication Needed*, GAO-02-785 *(Washington, D.C.: Aug. 26, 2002).* We surveyed the 47 state pipeline agencies about their opinions on integrity management, their plans for overseeing operator implementation, and communication with PHMSA.

[14]PHMSA and states do not know the exact number of integrity management inspections they will have to conduct because multiple operators may be included under one integrity management program.

[15]Inspections of operators without identified high consequence areas will be abbreviated and will ensure that the operators correctly made this determination and have a process to regularly reevaluate their system to identify any potential new areas that are subject to integrity management.

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

plan in March 2005 that considers the essential elements of such a plan. For example, the plan identifies trends likely to impact the number and types of field staff needed and identifies competencies needed to meet PHMSA's strategic goals. In addition, the plan includes an examination of how its workforce should be deployed across the organization and suggests assigning staff to regions based on regional workload and need.

State officials with whom we spoke reported additional staffing concerns as a result of integrity management inspections. State pipeline agencies generally employ between one and five inspectors to perform these inspections, although they may not be dedicated to integrity management. The Pipeline Safety and Improvement Act of 2002 increased the workload of state pipeline agencies by establishing three new inspection requirements for integrity management, operator qualifications and public awareness programs.[17] However, state staffing and funding levels were generally not increased to fulfill these additional responsibilities. States are handling the increased workload in various ways, such as combining inspections, modifying the frequency of inspections, or focusing efforts on completing one new inspection at a time. For example, a few states focused on completing operator qualifications inspections before starting integrity management inspections. In addition, 11 state officials said that it is difficult to hire qualified staff, such as engineers, who are needed for the technical nature of the integrity management inspections. According to two state officials, state agencies are losing trained inspectors because the state salaries are typically lower than those paid by operators. To help states deal with increased workload and hiring issues, the National Association of Pipeline Safety Representatives has recommended that PHMSA be allowed to reimburse state pipeline agencies up to 80 percent of their inspection program costs—up from the current allowance of up to 50 percent of program costs. PHMSA supports this increase, and such an increase is included as part of the proposed Pipeline Safety Improvement Act of 2006 (H.R. 5678 and H.R. 5782).[18]

[17]In addition to integrity management programs, all pipeline operators are required to have operator qualification programs to ensure that the individuals who perform certain safety tasks are qualified to conduct such tasks and public education programs on pipeline safety issues, such as one-call notification, the hazards of unintended releases, and the steps to take if there is a release and the procedure for reporting a release.

[18]GAO, *Gas Pipeline Safety: Views on Proposed Legislation to Reauthorize Pipeline Safety Provisions*, GAO-06-1027T (Washington, D.C.: Aug. 4, 2006).

PHMSA and about half of the state pipeline agencies have begun conducting inspections of operators' implementation of the integrity management requirements. PHMSA and states generally started initial integrity management inspections in 2005.[19] As of June 2006, PHMSA reported having completed 20 of about 100 inspections, encompassing about 7,063 of the 10,039 miles in high consequence areas that PHMSA is responsible for inspecting. About half of the state pipeline agencies reported that they had started or completed 117 of about 670 inspections as of January 31, 2006. In response to our survey, most of the remaining states reported that they anticipate beginning inspections in 2006. PHMSA selected the operators for initial inspections based on their history of working well with PHMSA and their expected level of program development to allow PHMSA inspectors to gain experience with its inspection protocols and process. After the first nine inspections, PHMSA met with inspectors to discuss the process and has made some revisions to the protocols based on inspectors' recommendations. PHMSA's current and future inspection schedule is determined by using a risk-ranking system that considers factors such as an operator's compliance history and pipeline mileage. Using this system should result in inspections of operators with a higher potential of having an incident or problem prior to those operators with a lower potential. According to PHMSA's "Guidelines for States Participating in the Pipeline Safety Program," states should use the date of the last inspection and operating history to prioritize operators for inspections. Seven state officials told us they initially inspected all operators' programs to ensure they had a program and had identified their high consequence areas, and that a more detailed inspection would be done in the future.

According to a PHMSA official and state officials, initial integrity management inspections show that operators are generally experiencing few problems with assessing and repairing pipelines, although some operators are having trouble documenting their processes and procedures and thus are failing to get adequate credit for their efforts. PHMSA considers documentation important for ensuring that an operator is appropriately implementing the program, that the operator is committed to continued implementation, and that the program is being consistently implemented throughout an operator's organization. It is also important to document the processes and procedures so that knowledge of the process

[19]Texas began inspections in 2001 for the state integrity management regulations that were in place prior to the federal integrity management regulations.

is not lost as staff changes occur. According to PHMSA, the documentation should include identifying the person involved in the decision or task, information needed and steps taken to make the decision or complete a task, and the results. Two state officials said that the operators in their states with few transmission pipeline miles were making efforts to comply but that they were struggling with implementing integrity management requirements. For example, the operator of a paper mill that also owns and operates about 8 miles of gas transmission pipeline to transport gas to its production facility stated that it is struggling to understand and comply with integrity management requirements. According to PHMSA and state officials, as operators continue developing and implementing their integrity management programs, and as they are provided feedback during inspections, the issues identified during these initial inspections should be resolved.

PHMSA is continuing to determine the appropriate enforcement actions, if any, as a result of its initial inspections and will consider all available enforcement tools, including civil penalties. As of June 30, 2006, six enforcement actions have been processed but no fines have been assessed. Four operators have been issued a Notice of Amendment, which indicates a need to improve their written processes and procedures. In addition, two of these operators have also received a Notice of Probable Violation and Proposed Compliance Order for potentially failing to fully comply with the risk analysis requirement in the rule. According to a PHMSA official, the enforcement actions processed to date are proposed actions and will become final after the operators have had an opportunity for a hearing. PHMSA has developed a process that provides consistent standards for the inspectors and regional directors to use in determining when an enforcement action is warranted. The process lays out criteria to determine the severity of each issue identified during the inspection, whether enforcement action is appropriate and, if so, what type of action to take. As part of their agreements with PHMSA, most states are responsible for taking appropriate enforcement actions as a result of their inspections. Most state officials said that issues identified during their initial integrity management inspections have not warranted enforcement actions. However, one state official with whom we spoke issued a notice of violation to an operator that had not developed an integrity management plan. The operator, with about 11 miles of gas transmission pipelines, told the state that it was unaware of the requirement to develop an integrity management program. The state official told us that, after the inspection, the operator immediately began developing a program, and the state inspector is to revisit this operator within 6 months.

Conclusions

The gas integrity management program has made a promising start. The program's risk-based approach is supported by industry, state pipeline agencies, safety advocates, and operators. Although the national transmission pipeline system is extensive, much of the population that is potentially affected by a pipeline event is concentrated in highly populated areas, which will be provided additional protection through the program. Thus far, operators are successfully implementing the critical assessment and repair requirements, and their documentation concerns should be resolved as operators gain experience with the program and receive feedback during inspections. While the progress in implementing the program to date is encouraging, PHMSA and state oversight will be critical to ensure that operators continue to effectively implement integrity management. As the program matures, PHMSA's performance measures should allow the agency to quantitatively demonstrate the program's impact on the safety of pipelines. However, relatively minor changes in how some of the measures are reported could help improve their usefulness and PHMSA's ability to analyze and demonstrate the program's impact over time.

Recommendations for Executive Action

To improve the consistency and usefulness of the integrity management performance measures, we are recommending that the Secretary of Transportation direct the Administrator for the Pipeline and Hazardous Materials Safety Administration to take the following two actions:

- revise the definition of a reportable incident to consider changes in the price of natural gas and
- establish consistent categories of causes for incidents and leaks on all gas pipeline reports.

Agency Comments and Our Evaluation

We provided a draft of this report to DOT for review and comment. We received oral comments from DOT officials, including the Assistant Administrator and Chief Safety Officer of PHMSA. The officials generally agreed with the report's findings and recommendations. They agreed with the need to revise the definition of a reportable gas transmission pipeline incident, noting that doing so provides a more realistic and consistent basis for reporting. PHMSA has already begun informal discussions with various parties on this issue and expects to initiate the rule making necessary to change the definition of a reportable gas incident soon. The officials also agreed with the recommendation to have consistent categories of causes for incidents and leaks for all gas pipeline reports. PHMSA is evaluating several alternatives to reconcile the differences in the categories and expects to initiate action to implement this recommendation.

We are sending copies of this report to congressional committees and subcommittees with responsibility for transportation safety issues; the Secretary of Transportation; the Administrator, PHMSA; the Assistant Administrator and Chief Safety Officer, PHMSA; and the Director, Office of Management and Budget. We will also make copies available to others upon request. This report will be available at no charge on the GAO Web site at http://www.gao.gov.

If you have any questions about this report, please contact me at siggerudk@gao.gov or (202) 512-2834. Contact points for our offices of Congressional Relations and Public Affairs may be found on the last page of this report. Staff who made key contributions to this report are listed in appendix III.

Katherine A. Siggerud
Director, Physical Infrastructure Issues

Congressional Committees

The Honorable Ted Stevens
Chairman
The Honorable Daniel K. Inouye
Co-Chairman
Committee on Commerce, Science
and Transportation
United States Senate

The Honorable Don Young
Chairman
The Honorable James L. Oberstar
Ranking Democratic Member
Committee on Transportation
and Infrastructure
House of Representatives

The Honorable Joe Barton
Chairman
The Honorable John D. Dingell
Ranking Minority Member
Committee on Energy and Commerce
House of Representatives

Scope and Methodology

The Pipeline Safety Improvement Act of 2002 directed GAO to assess the effects on public safety stemming from the gas transmission pipeline integrity management program. Accordingly, the objectives of our report were to examine (1) the effect on public safety of the gas transmission pipeline integrity management program and (2) the plans of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and state pipeline safety agencies to oversee gas transmission pipeline operators' implementation of integrity management requirements. To address these objectives, we reviewed laws, regulations, performance measure data, and PHMSA guidance and inspection reports related to the gas integrity management program. We also interviewed PHMSA officials and representatives from gas pipeline trade associations, pipeline safety advocacy groups, state pipeline agencies, and gas transmission pipeline operators. In addition, we reviewed prior GAO reports related to pipeline safety.

To determine the effect that the gas integrity management program requirements have had on public safety, we analyzed how those requirements compare with minimum safety requirements to understand what additional requirements operators were subject to as a result of integrity management. We discussed with PHMSA officials how the regulations were designed and developed to improve public safety. Since the integrity management requirements apply to a relatively small percentage of all transmission pipeline miles—about 7 percent—we estimated the percentage of the population living along pipelines that should receive additional protection as a result of integrity management because they are located in highly populated areas. We used Census data to estimate the percentage of the population that lives within 660 feet of a transmission pipeline that are located in urban areas, which would be considered highly populated areas. We used Census data to identify highly populated areas because the specific locations that operators have identified as high consequence areas were not readily available. Operators have identified a total of 20,294 miles of gas transmission pipelines in high consequence areas, and we have likewise identified a total of about 22,000 miles of pipelines in highly populated areas. Therefore, our estimate of pipelines in highly populated areas is a reasonable approximation of the pipelines in high consequence areas.

To identify and understand the benefits and challenges the operators face in developing and implementing their integrity management programs, we contacted 51 gas transmission pipeline operators to discuss their experiences and views on the program. We selected a range of operators with either large or small numbers of transmission pipeline miles since this could indicate the level of resources a particular operator would have to draw from to develop its integrity management program. We also selected operators based on a mixture of interstate and intrastate operators and considered the proportion of pipeline miles that each operator had in high consequence areas in our selection process. The information that we obtained from these operators is not generalizable to all gas transmission pipeline operators. We also discussed the integrity management program and its requirements with gas pipeline trade associations, pipeline safety advocacy groups, and state pipeline agencies to obtain their opinions on the benefits, challenges, and performance measures of the program.

In addition, we analyzed the integrity management performance measure data reported by operators to PHMSA. We assessed the internal controls and the reliability of the data elements needed for this engagement and determined that they were sufficiently reliable for our purposes. We compared the reporting requirements for integrity management performance measures with other pipeline reported data. Given the early stages of implementation of the integrity management program, we determined that there was not enough comparable historical data to conduct a trend analysis to quantify the impact of the program to date.

To determine PHMSA's plans to oversee operators' implementation of the integrity management program, we spoke with PHMSA officials about the inspection tools it developed to understand the purpose of the tools, their development, information that both federal and state inspectors receive about them, and plans for continual evaluation and improvement of the inspection program. We also reviewed the integrity management regulations, inspection protocols, supplemental guidance, frequently asked questions, and other guidance documents that inspectors may use to conduct integrity management inspections. While we compared the inspection protocols with the gas integrity management regulations to ensure that the protocols are aligned with the regulations, we did not evaluate the adequacy of these documents. We reviewed PHMSA requirements for both integrity management and core training, the schedule of training classes, and attendance records of state inspectors who have attended training on the inspection protocols. We also reviewed PHMSA's schedule of inspections and documentation on how the agency prioritizes operators for inspections. In addition, we reviewed PHMSA's workforce plan dated March 2005 to understand the agency's efforts to identify the resources and expertise needed for integrity management.

To understand the plans of state pipeline agencies to oversee operators' implementation of integrity management requirements, we surveyed the 46 state pipeline agencies and the District of Columbia pipeline agency that have responsibility for conducting gas integrity management inspections.[1] We pretested the survey with three states prior to deployment. The survey covered state plans for inspections, resources and challenges, and communication with PHMSA. All 46 state agencies and the District of Columbia responded to our survey. (See app. II for a copy of the survey and aggregated results.) We then selected 15 states to contact to gain additional information on challenges the states face as a result of integrity management, benefits of the program to the pipeline industry, results of inspections started or completed, performance measures, and communication with PHMSA. We considered the following factors when selecting states to contact: geographic dispersion, whether inspections had been started or completed as of January 31, 2006, and whether states reported facing staffing and/or training challenges to a great or very great extent. In addition, we contacted three states prior to developing the survey. In total, we spoke with officials from 21 state pipeline agencies. These state agencies started or completed 103 of the 117 inspections started or completed, as of January 31, 2006. However, the information obtained from these conversations is not generalizable to all state pipeline agencies. We also reviewed documents from the National Association of Pipeline Safety Representatives to better understand the role of state pipeline agencies in overseeing operators. We also reviewed PHMSA's guidance for state pipeline programs but did not evaluate PHMSA's oversight of state pipeline programs.

To understand the extent to which operators were complying with the integrity management requirements, we reviewed reports from 10 PHMSA inspections and 10 inspections from two states. Our review of the inspection reports was for illustrative purposes, and the results of our review cannot be generalized to all operators. We also spoke with PHMSA officials about their enforcement program and enforcement actions to date, and we reviewed regulations and PHMSA guidance on what enforcement actions may be taken and how PHMSA determines the appropriate action to take as a result of gas integrity management inspections. Since states

[1]We initially sent the survey to pipeline agencies in 48 states, the District of Columbia and Puerto Rico, however, we excluded two states (Connecticut and Rhode Island) and Puerto Rico since they did not have any intrastate gas transmission pipeline operators and therefore, have no responsibility for conducting these inspections. Alaska and Hawaii do not have state pipeline agencies, so the survey was not sent to them.

were not required to develop a separate enforcement plan for gas integrity management and most state officials with whom we spoke had not taken any enforcement actions, we did not review state enforcement programs.

Results of State Pipeline Agency Survey

United States Government Accountability Office

Survey of State Pipeline Agencies:
Gas Integrity Management Program Inspections

Introduction

The U.S. Government Accountability Office (GAO), an independent congressional agency, was required by the Pipeline Safety Improvement Act of 2002 (PL 107-355), to assess and evaluate the effects on public safety of the requirements for the implementation of gas transmission pipeline integrity management programs (IMP). As part of our work, GAO is reviewing how the Office of Pipeline Safety (OPS) within the Pipeline and Hazardous Materials Safety Administration plans to ensure that pipeline operators are complying with the IMP regulations. Given state pipeline agencies' role in inspecting intrastate pipeline operators, we would like to understand the extent to which states will be inspecting operators' implementation of IMP. The following survey is intended to help us understand state plans for conducting IMP inspections, including the development of an inspection program and resources required to conduct inspections. GAO is not auditing state inspection programs in any way.

Instructions for Completing This Questionnaire

This questionnaire can be filled out using MS-Word and returned via Email, or if you prefer, you may print the questionnaire and complete it by hand. If you complete it by hand, you can return your survey via fax or mail.

If you are completing the survey in MS-Word, follow these instructions:

- Please use your mouse to navigate by clicking on the field or check box ☐ you wish to answer.
- To select a check box or button, simply click on the center of the box.
- To change or deselect a check box response, simply click on the check box and the 'X' will disappear.
- To answer a question that requires that you write a comment, click on the answer box ____ and begin typing. These boxes are highlighted in yellow. The box will expand to accommodate your answer.

To assist us, we ask that you complete and return this survey by **Friday**, **March 3, 2006**.

To return by Email: Once the survey is completed, save this file to your computer desktop or hard drive and attach the file as part of your Email message to FrevertH@gao.gov or EdelsteinM@gao.gov.

To return by fax: Print the survey, complete it by hand, and fax it to: 202-512-4852. Please fax to the attention of Heather Frevert or Maria Edelstein.

To return by mail: Print the survey, complete it by hand, and mail it to:

Heather Frevert or Maria Edelstein
GAO
441 G Street, NW, Room 2T23B
Washington, DC 20548

If you have any questions about the contents of this questionnaire, please contact:

Heather Frevert		Maria Edelstein
Phone: (202) 512-4203	OR	Phone: (202) 512-6449
e-mail: FrevertH@gao.gov		e-mail: EdelsteinM@gao.gov

1

Respondent Information

Please provide the following information for the individual coordinating the completion of this survey so that we may contact them to clarify any responses, or obtain additional information, if necessary.

Name:

Title:

Agency:

Telephone Number: **( ) - , Ext:**

E-mail Address: @

Before completing the survey, please note the following:

- Unless otherwise indicated, all responses should be made about your program at the state level.
- There is space for your comments at the end of the survey.
- We recognize that it is early in the IMP implementation process, and that your program may change, as well as your opinions about the process. We ask that you answer these survey questions as they pertain to your current program status and your opinions as of today.

Integrity Management Program Regulations

1. How many gas transmission pipeline operators do you currently have oversight responsibility for?

	No. of Operators	Frequency
Operators	1-20	39
	21-50	6
	over 50	2

2. How many gas integrity management program (IMP) plans do you expect to have oversight responsibility for, given that multiple operators may follow the same IMP plan?

	No. of IMPs	Frequency	
Plans	1-20	41	
	21-50	3	
	over 50	2	(Note: No response = 1)

2

3. **Does your state have its own gas IMP regulations that are separate from the federal IMP regulations?**

No (46)

Yes (1) → **3a. If yes, briefly explain how your regulations are different than federal IMP regulations.**

4. **To what extent do you expect that gas IMP requirements will protect public safety?**

Very great extent .... (3)
Great extent .... (10)
Moderate extent........................ (16)
Some extent .... (8)
Little or no extent .... (0)
Don't know................................ (9) (Note: No response = 1)

5. **In measuring the effectiveness of the gas transmission integrity management regulations, do you currently collect any performance measures that are above and beyond what the federal gas IMP rules require?**

No (45)
Yes (2)

6. **In your opinion, are additional federal performance measures needed to measure the effectiveness of the gas transmission integrity management regulations?**

No (17)
Yes (4)
Undecided (25) (Note: No response = 1)

3

Gas Integrity Management Program Inspections

7. **Will you follow the Office of Pipeline Safety's (OPS) inspection protocols when conducting gas IMP inspections?**

Yes, with no changes to the protocol .... (43) → ***SKIP TO QUESTION #9***
Yes, but with some changes to the protocol .... (3) → ***SKIP TO QUESTION #9***
No, we will not follow the OPS protocols............... (0) (Note: No response = 1)

8. **If you will not follow the OPS protocols when conducting inspections, will you use inspection protocols that your state developed?**

No n.a. (0 responses to "No, we will not follow . . .", above)
Yes n.a. (0 responses to "No, we will not follow . . .", above)

9. **Has your state started inspections of gas IMP plans?**

(23) No → ***SKIP TO QUESTION #10***
(23) Yes

a. **On approximately what date did you start the inspections?**

/ (*MM/ /YY)* (Responses ranged from 3/05 to 2/06, with one respondent starting inspections in 5/01)

b. **As of January 31, 2006, how many gas IMP inspections have been <u>completed</u>?**

Inspections (7 Respondents reported 0 completed inspections, 9 reported between 1 and 3, 3 reported between 4 and 7, and 1 reported 50, and 3 indicated no response)

c. **As of January 31, 2006, how many gas IMP inspections have been <u>started but not completed</u>?**

Inspections → ***SKIP TO QUESTION #11*** (8 respondents reported 0, 9 respondents reported between 1 and 4, 1 reported 9, 1 reported 12, 4 gave no response).

10. **If you have <u>not</u> begun inspections, have you set a date for gas IMP inspections to begin?**

(5) No

(17) Yes → **On approximately what date will inspections begin?**
(Responses ranged from April 2006 through the end of 2006, with 1 respondent saying 2007)
(Note: No response = 1)

4

11. How long do you anticipate it will take your state to inspect all of the gas IMP plans you are responsible for?

Up to one year	23
Between one and two years	15
Between two and three years	4
More than three years	3
Other time frame (please specify)	0

(Note: No response = 2)

12. How often do you anticipate that you will inspect each of the gas IMP plans you are responsible for?

Once a year	10
Once every two years	16
Once every three years	14
Other time frame(s) (please specify)	6

(Note: No response = 1)

13. Do you plan to report the results of completed gas IMP inspections to OPS?

No 7 → **If no, please explain:** (Note: 5 explained there is no requirement to report)

Yes 28

Undecided 10

(Note: No response = 2)

State Resources

14. How would you describe the number of staff that your agency currently has to implement the gas IMP inspection program?

We do not have enough staff at this time	27
We have enough staff at this time	18
We have more than enough staff at this time	1

(Note: No response = 1)

15. How many inspectors do you currently have that can perform gas IMP inspections?

Inspectors

Inspectors	Frequency
0	3
1	14
2	15
3	5
4	7
5	3

5

16. To date, how many inspectors received OPS training on inspection protocols, and are currently available to conduct inspections?

Inspectors

Inspectors	Frequency
0	4
1	13
2	17
3	5
4	4
5	4

17. To what extent has the state's frequency of conducting other pipeline inspections been impacted by the addition of gas IMP inspections?

Very great extent 2
Great extent 7
Moderate extent 17
Some extent 9
Little or no extent 7

Don't know 5

18. To what extent does your agency experience the following challenges as a result of implementing the gas IMP inspection program?

	A very great extent	Great extent	Moderate extent	Some extent	Little or no extent	Not sure	(No answer)
a. Staffing challenges?	7	11	15	6	6	2	
b. Funding challenges?	5	7	7	10	13	4	1
c. Training challenges?	8	16	12	7	3	0	1
d. Another challenge? (please describe)	7	5	2	0	0	4	29
e. Another challenge? (please describe)	2	1	0	1	0	4	39

6

19. How useful has the overall guidance that OPS has provided on your IMP inspection roles and responsibilities been?

Extremely useful........................4
Very useful................................23
Moderately useful 9
Somewhat useful........................5
Not at all useful 1

Don't know 5

20.

	A. Have the following sources provided you information or guidance on conducting gas IMP inspections?			B. Is this a main source of information or guidance on conducting gas IMP inspections?		
	Yes	No	No response	Yes	No	No response
a. OPS State Liaison?..............	24	19	3	7	34	6
b. Other OPS Regional Staff?...	34	11	2	20	22	4
c. OPS Training Staff?	40	6	1	34	9	4
d. National Association of Pipeline Safety Representatives (NAPSR)?	22	21	4	5	33	9
e. Other source? (please describe)...................	14	1	32	7	5	35

21. Please provide any additional comments that you have in this space. If your comments are in response to a particular question, please indicate the question number to which you are referring.

Thank you for completing the survey!

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Contact and Staff Acknowledgments

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Staff Acknowledgments

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