



June 2013

GAS PIPELINE SAFETY

Guidance and More Information Needed before Using Risk- Based Reassessment Intervals

GAO Highlights

Highlights of [GAO-13-577](#), a report to congressional committees

Why GAO Did This Study

About 300,000 miles of gas transmission pipelines cross the United States, carrying natural gas from processing facilities to communities and large-volume users. These pipelines are largely regulated by PHMSA. The Pipeline Safety Improvement Act of 2002 established the gas integrity management program, which required gas transmission pipeline operators to assess the integrity of their pipeline segments in high consequence areas by December 2012 and reassess them at least every 7 years.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 directed GAO to examine the results of these baseline assessments and reassessments and the potential impact of making the current process more risk-based. GAO analyzed (1) PHMSA's assessment data on repairs made and the appropriateness of the 7-year reassessment requirement, (2) the impact of the 7-year reassessment requirement on regulators and operators, and (3) the potential challenges of implementing risk-based reassessment intervals beyond 7 years. GAO analyzed assessment data; reviewed legislation and regulations; and interviewed pipeline operators, federal and state regulators, and other stakeholders.

What GAO Recommends

DOT should (1) develop guidance for operators to calculate reassessment intervals and (2) collect information on the resources needed to implement risk-based reassessment intervals beyond 7 years. DOT did not agree or disagree with the recommendations, but provided technical comments.

View [GAO-13-577](#). For more information, contact Susan A. Fleming at (202) 512-2834 or flemings@gao.gov.

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What GAO Found

Baseline assessment and reassessment data collected by the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) since 2004 show that pipeline operators are making repairs in highly populated or frequented areas ("high consequence areas"). For example, from 2004 to 2009, operators made 1,080 immediate repairs. While operators can use assessment data to determine reassessment intervals for specific pipelines, PHMSA's data are aggregated and cannot indicate an appropriate maximum interval for all pipelines nationwide. Such a determination requires, for example, collaboration of subject matter experts and analysis of technical studies.

The current 7-year reassessment requirement provides a safeguard by allowing regulators and operators to identify and address problems on a continual basis, but is not fully consistent with risk-based practices. The 7-year reassessment requirement is more frequent than the intervals found in industry consensus standards and provides greater assurance that operators are regularly monitoring their pipelines to address threats before leaks or ruptures occur. However, this requirement—which was established in a 2002 act as part of the gas integrity management program rather than by rulemaking—is not fully consistent with risk-based management practices, which ask operators to, for example, use information to identify, assess, and prioritize risks so that resources may be allocated to address higher risks first. While operators are required to determine an appropriate reassessment interval based on the threats to their pipelines in high consequence areas, they must reassess those pipelines at least every 7 years regardless of the risks identified.

Implementing risk-based reassessment intervals beyond 7 years would require a statutory change from Congress and could exacerbate current workload, staffing, and expertise challenges for regulators and operators. For example, PHMSA is facing workload problems with inspections, which could be worsened by allowing operators to use risk-based reassessment intervals beyond 7 years; PHMSA has an initiative under way that could help address this issue. Further, some operators told us that extending reassessment intervals beyond 7 years would likely require additional data analyses over what is currently required. Operators GAO met with varied in the extent to which they currently calculate reassessment intervals and use the results of data analyses. Guidance to calculate reassessment intervals is lacking, and as a result, operators may perform a less rigorous determination of their reassessment intervals at this time. At Congress's request, in 2008 PHMSA described how it would establish and enforce risk-based criteria for extending the 7-year reassessment interval. PHMSA proposed retaining the current 7-year reassessment requirement, but establishing a process by which operators could use risk-based reassessment intervals beyond 7 years if they met certain potential criteria, such as demonstrating sound risk analysis. While PHMSA and GAO have supported the concept of risk-based reassessment intervals beyond 7 years, given the breadth of potential challenges with implementation, more information might help decision-makers better understand the resource requirements for this change. For example, PHMSA has used pilot programs to collect such information and study the effects prior to rule changes.

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Abbreviations

2002 act	Pipeline Safety Improvement Act of 2002
ASME	American Society of Mechanical Engineers
PHMSA	Pipeline and Hazardous Materials Safety Administration

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June 27, 2013

The Honorable John D. Rockefeller IV
Chairman
The Honorable John Thune
Ranking Member
Committee on Commerce, Science, and Transportation
United States Senate

The Honorable Fred Upton
Chairman
The Honorable Henry Waxman
Ranking Member
Committee on Energy and Commerce
House of Representatives

The Honorable Bill Shuster
Chairman
The Honorable Nick J. Rahall, II
Ranking Member
Committee on Transportation and Infrastructure
House of Representatives

About 300,000 miles of transmission pipelines across the United States carry natural gas from processing facilities to communities and large-volume users, such as power plants and factories. These pipelines, which are largely regulated by the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), are relatively safe when compared with other modes of transporting hazardous goods (e.g., highway and rail). However, when pipelines leak or rupture, the results can be devastating, including fatalities, injuries, and extensive property or environmental damage. Such an incident occurred in September 2010 in San Bruno, California, killing eight people and damaging or destroying over 100 homes.

The Pipeline Safety Improvement Act of 2002 (2002 act) required PHMSA to implement a risk-based approach to gas transmission pipeline safety, an approach known as "integrity management." The integrity management program requires operators to, among other things, systematically identify threats and mitigate risks to pipeline segments located in "high consequence areas," which include highly populated or frequented areas. Specifically, the 2002 act required operators of gas

transmission pipelines to complete a baseline assessment looking for safety threats to their pipelines in high consequence areas by December 2012, and complete reassessments of those pipelines at least every 7 years,¹ a time frame that some stakeholders feel is too frequent. PHMSA and state pipeline safety offices conduct inspections and other efforts to oversee operators' compliance with this program.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 mandated that GAO examine the results of baseline assessment and reassessment data for gas transmission pipelines, as well as the impact to stakeholders of making assessments more risk-based.² This report contains information on: (1) the extent to which PHMSA's assessment data provides information on repairs made and the appropriateness of the 7-year reassessment requirement, (2) the impact of the 7-year reassessment requirement on regulators and operators, and (3) the potential challenges of implementing risk-based reassessment intervals beyond 7 years.

To address the extent to which PHMSA's assessment data provides information on repairs and the appropriateness of the 7-year reassessment requirement, we analyzed PHMSA data from 2004 to 2011 on gas transmission pipelines, including: age and operating pressure of transmission pipelines, pipeline miles assessed, tools used to conduct assessments, and conditions found during assessments and subsequently repaired. We assessed the reliability of the PHMSA data by speaking with agency officials about data quality control procedures and reviewing relevant documentation. We determined that the data were sufficiently reliable to provide background information and to describe repairs made in high consequence areas. To determine the impact of the 7-year reassessment requirement as well as the potential challenges to regulators and operators of using risk-based reassessment intervals beyond 7 years, we reviewed relevant legislation, PHMSA regulations, and PHMSA documents. We also interviewed selected federal and state regulators, industry associations, gas transmission pipeline operators, pipeline safety advocacy and environmental groups, research firms, a state regulatory association, and technical experts. We spoke with a non-

¹Pub. L. No. 107-355, § 14(a), 116 Stat. 2985, 3002 (2002) (codified as amended at 49 U.S.C. § 60109(c)(3)(A)-(B)).

²Pub. L. No. 112-90, § 5(g), 125 Stat. 1904, 1909 (2012).

generalizable sample of 27 gas transmission pipeline operators that we selected using several criteria, including the number of pipeline miles in high consequence areas, recent incidents caused by corrosion, and geographic location. We also spoke with a non-generalizable sample of 8 state pipeline safety offices that were selected based on several factors, including total pipeline mileage within the state and geographic location. We collected additional information from three pipeline operators on their experience calculating reassessment intervals and conducting reassessments. For more information on our scope and methodology, see appendix I.

We conducted this performance audit from July 2012 to June 2013 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

The United States has a network of about 300,000 miles of gas transmission pipelines that are owned and operated by approximately 900 operators. These pipelines, which are primarily interstate, typically move gas products over long distances from sources to communities, and tend to operate at the highest pressures and have the largest diameters of any type of pipeline.³ Gas transmission pipelines are critical because they transport nearly all of the natural gas used in the United States, which fuels about a quarter of the nation's energy needs. Pipelines do not experience many of the safety threats faced by other forms of freight transportation because they are mostly underground. However, they are subject to problems that can occur over time (such as leaks and ruptures resulting from corrosion) or are independent of time (such as damage from excavation, land movement, or incorrect operation).

PHMSA administers the national regulatory program to ensure the safe transportation of natural gas and hazardous liquids (e.g., petroleum or

³Gathering pipelines collect gas from production areas and transport it to processing facilities, which in turn refine and send the products to transmission pipelines. Local distribution pipelines, which are primarily intrastate, receive gas from transmission pipelines and distribute it to commercial and residential end users.

anhydrous ammonia) by pipeline, including developing safety requirements that all pipeline operators regulated by PHMSA must meet.⁴ In fiscal year 2012, the agency's total budget was \$201 million, about half of which is for pipeline safety activities. PHMSA's Office of Pipeline Safety employs over 200 staff, with about 135 of those staff involved in inspections and enforcement. In addition, over 300 state inspectors help oversee pipelines and ensure safety.

Pipeline operators are subject to PHMSA's minimum safety standards for the design, construction, testing, inspection, operation, and maintenance of gas transmission pipelines. However, this approach does not systematically account for differences in the kinds of threats and the degrees of risk that individual pipelines face. For example, pipelines located in the Pacific Northwest are more susceptible to damage from geologic hazards, such as land movement, than pipelines in some other areas of the country. Federal efforts to incorporate risk-based concepts into pipeline management began in earnest in the mid-1990s. For example, the Accountable Pipeline Safety and Partnership Act of 1996 required the Department of Transportation to establish risk management demonstration projects.⁵ The purpose of this effort was "to demonstrate, through the voluntary participation by owners and operators of gas pipeline facilities and hazardous liquid facilities, the application of risk management; and to evaluate the safety and cost-effectiveness of the program."⁶ These projects helped PHMSA establish a more risk-based approach to safety: the integrity management program. Integrity management helps ensure safety by, among other things, using information to identify and assess risks and prioritizing risks so that resources may be allocated to address higher risks first. The integrity management program requires operators to perform a number of activities, such as identifying high consequence areas and pipelines

⁴PHMSA does not regulate all pipelines. For example, many gathering pipelines have not been subject to PHMSA regulations because they are generally located away from population centers, operate at low pressures, or primarily involve intrastate pipelines.

⁵Pub. L. No. 104-304, § 5, 110 Stat. 3798 (1996).

⁶49 U.S.C. § 60126(a)(1)(A), (B).

within those areas,⁷ as well as identifying the threats facing those pipelines. PHMSA first implemented integrity management requirements for hazardous liquid pipeline operators with 500 or more miles of pipelines in December 2000, followed by hazardous liquid pipeline operators with less than 500 miles in January 2002. The Pipeline Safety Improvement Act of 2002 extended the integrity management program to gas transmission pipelines, which include about 20,000 miles of pipeline segments located in high consequence areas.⁸ In addition to being subject to PHMSA's integrity management program, operators must still meet the minimum safety standards noted above.

As part of the integrity management program, operators are required to assess the integrity of their pipelines within high consequence areas on a regular basis using approved methods. Specifically, gas transmission pipeline operators were required to complete a baseline assessment on pipeline segments within high consequence areas by December 17, 2012. According to the 2002 act, operators are then required to complete reassessments of these pipelines at least every 7 years. Gas transmission pipeline operators completed most baseline assessments by December 17, 2012, and reassessments are currently under way.⁹ From 2004 through December 2011 (the latest data available), baseline assessments were conducted on over 23,450 miles of gas transmission pipeline in high consequence areas.¹⁰ Over 4,470 miles of gas

⁷Examples of high consequence areas for gas transmission pipelines could include: (1) an area with 20 or more buildings that could be affected by a pipeline incident; (2) a location where a potential impact of a pipeline rupture contains an area or open structure that is occupied by 20 or more people on at least 50 days in a 12-month period (e.g., a camp site); or (3) a facility occupied by persons who would be difficult to evacuate, such as a hospital or school. 49 C.F.R. § 192.903.

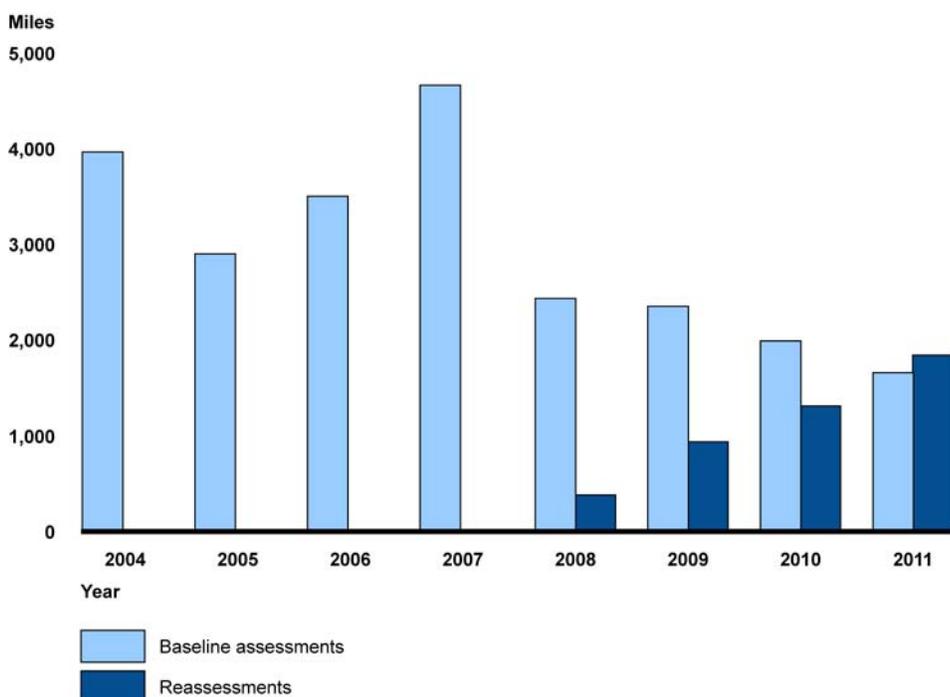
⁸Prior to enactment of the Pipeline Safety Improvement Act of 2002, PHMSA was exploring a rulemaking for integrity management for gas transmission pipelines.

⁹When a pipeline operator identifies a new high consequence area, the operator must complete the baseline assessment of the affected pipeline segment within 10 years from the date the high consequence area is identified. See 49 C.F.R. §192.921(f).

¹⁰The total gas transmission pipeline mileage within high consequence areas changes from year to year due to, for example, changes in the population near the pipeline, or as pipeline segments are placed in to or taken out of service. According to PHMSA's data, the total mileage from 2004 to 2011 has ranged from a low of 19,139 miles to a high of 21,765 miles. Given the annual change in pipeline miles in high consequence areas, the miles of completed baseline assessments and reassessments exceeds the current number of pipeline miles in high consequence areas.

transmission pipeline in high consequence areas—or about 20 percent of the pipeline miles that had a completed baseline assessment between 2004 and 2011—were reported as reassessed between 2008 and 2011 (see fig. 1).¹¹ Among other things, PHMSA’s integrity management regulations required operators to (1) prioritize their baseline assessments to assess riskier pipelines first and (2) complete baseline assessments of these riskier pipelines by December 2007, and all pipelines within high consequence areas by December 2012. As a result, a small spike in the mileage assessed occurred in 2007.

Figure 1: Gas Transmission Pipeline Mileage in High Consequence Areas Assessed by Pipeline Operators from 2004 to 2011



Source: GAO analysis of PHMSA data.

Note: According to PHMSA, data on assessments of gas transmission pipelines in high consequence areas between 2004 and 2009 may include over-reporting of the total miles assessed. In some cases,

¹¹PHMSA began collecting data on reassessments in 2008. Prior to 2008, pipeline operators could only report to PHMSA the number of miles on which they had conducted baseline assessments.

pipeline operators that used two different types of assessment tools may have reported to PHMSA the mileage assessed by these tools twice.

Under PHMSA's regulations, gas transmission pipeline operators may use any of three primary approaches to conduct assessments:

- *In-line inspection:* In-line inspection involves running a specialized tool—often known as a smart pig—through the pipeline to detect and record anomalies, such as metal loss and damage (see fig. 2). In-line inspection allows operators to determine the nature of any problems without either shutting down the pipeline for extended periods or potentially damaging the pipeline. In-line inspection devices can be run only from specific launch and retrieval points, which may extend beyond high consequence areas. Operators using in-line inspection will often gather information along the entire distance between launching and retrieval locations to gain additional safety information. Based on PHMSA's data, the majority of pipeline miles assessed in 2011 (88 percent) were done using in-line inspection.

Figure 2: In-Line Inspection Device Being Placed in a Launcher



Source: GAO.

- **Direct assessment:** Direct assessment is an aboveground assessment method used to identify problem areas on a pipeline. The process includes gathering data on potential risks facing the pipeline, analyzing those data to identify potential problem locations, and then excavating and directly examining those locations. PHMSA regulations require that at least two or more aboveground detection instruments, such as a close interval survey,¹² be used to constitute a direct assessment.
- **Hydrostatic testing:** Hydrostatic testing entails sealing off a portion of the pipeline, removing the gas product and replacing it with water, and increasing the pressure of the water above the rated strength of the pipeline to test its integrity. If the pipeline leaks or ruptures, the

¹²During a close interval survey, measurements of the soil along a pipeline's right-of-way are taken at regular distances (i.e., about every 3 feet) to determine if there is any corrosion damage to the pipeline.

pipeline is excavated to determine the cause of the failure. Operators must shut down pipelines to perform hydrostatic testing. Also, this assessment method can weaken the pipeline due to the high pressures involved, making it more susceptible to failure later. Finally, operators must be able to dispose of large quantities of waste water in an environmentally responsible manner.

According to the operators we spoke with, the costs associated with performing each of these assessment methods varies greatly. For example, operators told us that the estimated average cost for conducting a direct assessment ranges from \$5,000 per mile to \$500,000 per mile. The costs vary due to a number of factors, such as the amount of pipeline mileage to be assessed and the number of digs that must be performed after completing an assessment to confirm the findings.

PHMSA's regulations promulgated pursuant to the Pipeline Safety Improvement Act of 2002 require gas transmission pipeline operators to reassess their pipelines for *all safety risks*—such as corrosion, excavation, land movement, or incorrect operation—at regular intervals based on industry consensus standards. But the regulations limit the 7-year reassessment requirement in the 2002 act to *corrosion damage only* because corrosion is the most frequent cause of failures that can occur over time. The industry consensus standards adopted in PHMSA's regulations require that gas transmission pipeline operators reassess their pipelines for *all safety risks* at least every 10, 15, or 20 years,¹³ depending primarily on the condition and operating pressure of the pipelines, with pressure measured as a percentage of specified minimum yield strength.¹⁴ If an operator elects to establish a reassessment interval for all safety risks based on the industry consensus standards, it must—in order to comply with the 2002 act—perform what is called a “confirmatory direct assessment” by at least the seventh year to assess corrosion

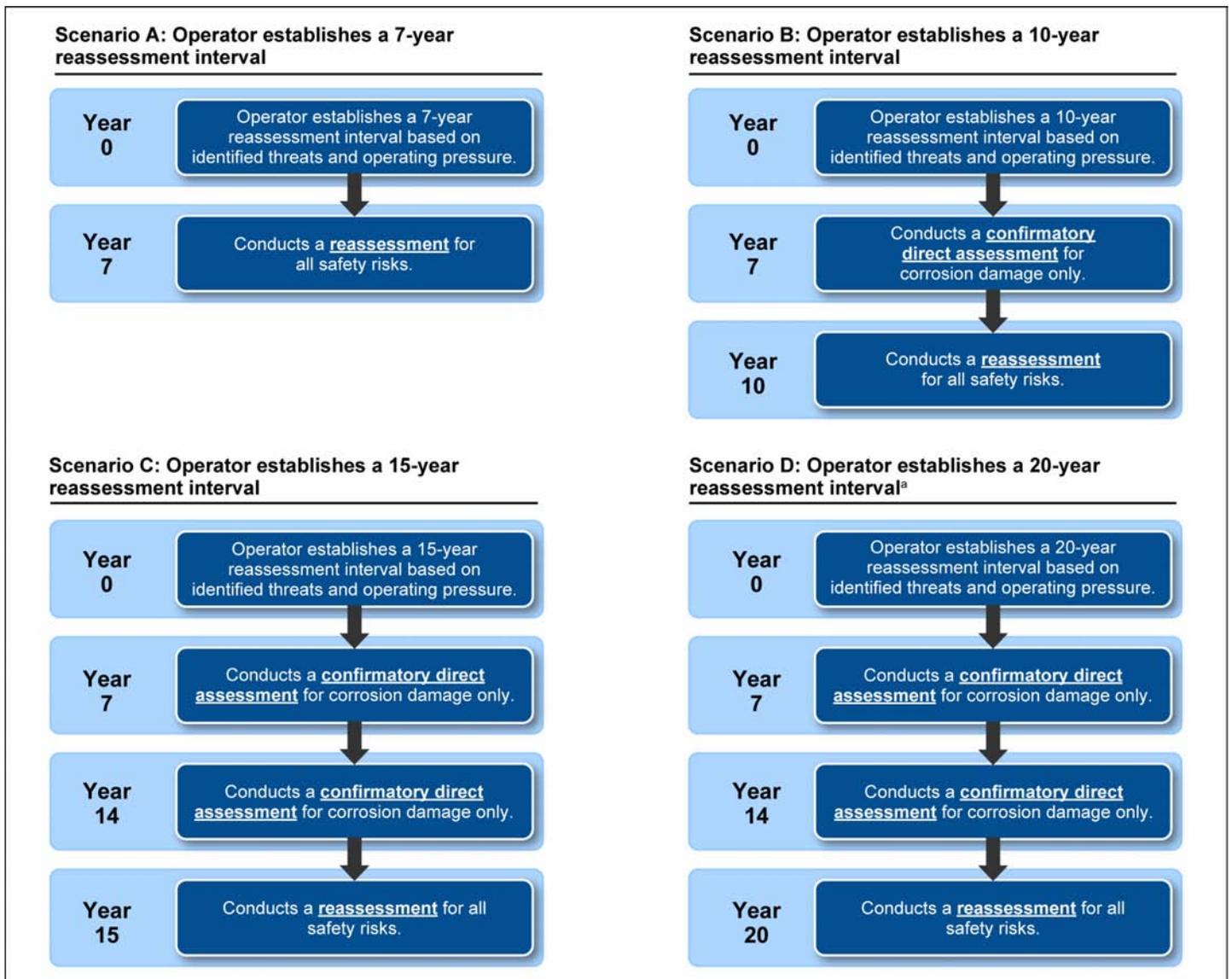
¹³49 C.F.R. § 192.939.

¹⁴Pipelines will begin to deform at a certain level of operating pressure. As a result, pipelines operate at a percentage of the level of pressure that will cause the pipeline to deform, known as “specified minimum yield strength.” The specified minimum yield strength depends on the type of metal and is an indicator of when the metal in the pipe starts to yield, deforming in a way that does not return to its original shape. By definition, transmission pipelines operate at or above 20 percent of specified minimum yield strength. 49 C.F.R. § 192.3.

damage,¹⁵ and then conduct the reassessment for all safety risks at the interval the operator established. Alternatively, an operator can elect to perform a reassessment for all safety risks (including corrosion damage) at least every 7 years in order to comply with both the 2002 act and PHMSA's regulations. Figure 3 provides some examples in which an operator can meet its reassessment requirements, either through performing (1) a confirmatory direct assessment at year 7 and a reassessment for all safety risks at a later year that comports with the industry consensus standards, or (2) a reassessment for all safety risks every 7 years.

¹⁵Confirmatory direct assessment is similar to direct assessment; however, operators are required to use only one type of assessment tool, rather than at least two types as required for direct assessment.

Figure 3: Some Examples in Which a Gas Transmission Pipeline Operator Can Meet Reassessment Requirements



Source: GAO.

^aGas transmission pipeline operators with pipeline segments operating below 30 percent specified minimum yield strength and who elect to use a 20-year reassessment interval can choose to perform either a confirmatory direct assessment or a “low stress reassessment” by years 7 and 14. A low stress reassessment involves the operator performing various tests or surveys to identify potential changes in external or internal corrosion. See 49 C.F.R. § 192.941.

The 7-year reassessment requirement in the Pipeline Safety Improvement Act of 2002 as well as the reassessment intervals noted in PHMSA's regulations and the industry consensus standards are *maximum reassessment intervals*: they represent the *maximum* number of years between reassessments. If pipeline conditions and risks dictate more frequent reassessments, then pipeline operators must do so to comply with PHMSA's regulations.¹⁶ In addition, between reassessments, operators must—regardless of whether their pipeline mileage is located in a high consequence area—patrol their pipelines, survey for leakage, maintain valves, ensure that corrosion-preventing cathodic protection is working properly,¹⁷ and take measures to prevent excavation damage.

In general, PHMSA has full responsibility for inspecting interstate pipelines and enforcing regulations pertaining to them,¹⁸ although some states are designated as “interstate agents” to assist PHMSA.¹⁹ PHMSA also has arrangements with the 48 contiguous states, the District of Columbia, and Puerto Rico to assist with overseeing intrastate pipelines. State pipeline safety offices are allowed to issue regulations supplementing or extending federal regulations for intrastate pipelines, but these state regulations must be at least as stringent as the minimum federal regulations.

¹⁶Pipeline conditions and threats change over time. For example, housing may be built around pipelines, possibly increasing the threat of excavation damage. Another example is that over time the quality of the gas being shipped through the pipeline may change and may be more corrosive.

¹⁷Cathodic protection involves a small electrical voltage between a structure and the ground to control corrosion.

¹⁸49 U.S.C. § 60102.

¹⁹49 U.S.C. § 60106.

Data Show Critical Pipeline Repairs Are Being Made, but Cannot Be Used to Determine an Appropriate Maximum Reassessment Interval for All Pipelines Nationwide

Assessments Have Resulted in Critical Pipeline Repairs

PHMSA's baseline assessment and reassessment data from 2004 to 2011 show that pipeline operators have identified and are making critical repairs in high consequence areas, specifically for conditions requiring repairs immediately or within one year.²⁰ For immediate conditions, operators must make a repair as soon as possible and reduce pipeline operating pressure or shut down the pipeline until the repair is completed. A dent in a pipeline wall that also appears to have cracks would be considered a condition in need of immediate repair. For scheduled conditions,²¹ operators must make repairs within one year or observe the condition during subsequent assessments for any changes that would require repair. A dent with a depth of more than two percent of the

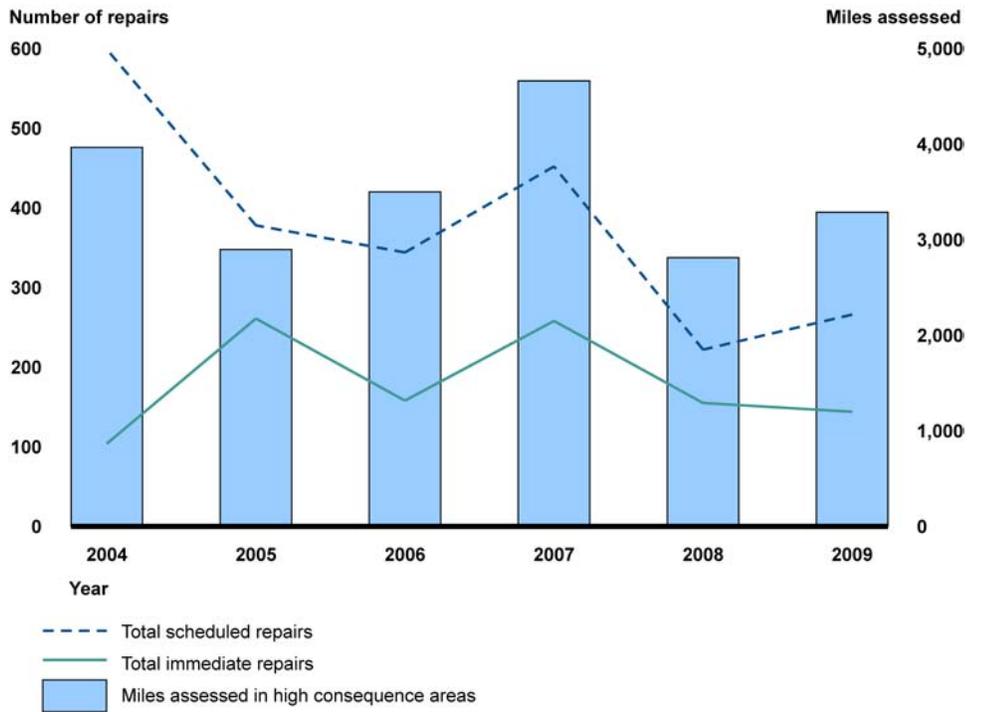
²⁰PHMSA regulations require that pipeline operators take prompt action to address all anomalous conditions the operator discovers through baseline assessments and reassessments. 49 C.F.R. § 192.933(a).

²¹For our review, we refer to one-year and monitored conditions as "scheduled" conditions. See 49 C.F.R. §§192.933(c), (d)(1), (d)(2), and (d)(3). PHMSA's data collection of scheduled repairs made from 2004 to 2009 did not differentiate between one-year and monitored conditions. According to PHMSA, this may have resulted in some pipeline operators reporting data on scheduled repairs differently. For example, some pipeline operators may have reported a scheduled repair as any non-immediate repair made; some may have reported only repairs of monitored conditions, not one-year repair conditions. PHMSA's 2010 and 2011 annual reports help address this by having pipeline operators report separately on the number of immediate repair conditions, one-year conditions, monitored conditions, and other "scheduled" conditions repaired.

pipeline's diameter located near certain sections of the pipeline wall would be considered a scheduled condition that must be repaired within one year. Pipeline operators report annually to PHMSA the number of immediate and scheduled repairs made on their pipelines that were identified through assessments. Miles assessed and repairs are reported in the year they are conducted. PHMSA data show that from 2004 to 2009, pipeline operators reported making 1,080 immediate repairs and 2,261 scheduled repairs (see fig. 4). The data also show that during 2010 and 2011, pipeline operators reported 387 immediate conditions repaired and 2,246 scheduled conditions repaired. A PHMSA official told us that a 2010 change in reporting requirements resulted in the increase in reported conditions repaired beginning in 2010.²²

²²In 2010, PHMSA changed how pipeline operators were required to report repair data. From 2004 to 2009, pipeline operators reported the number of repairs completed for immediate and scheduled conditions with one repair potentially fixing multiple conditions. For data collected in 2010 and later, pipeline operators were required to report the number of individual conditions repaired. As compared to 144 immediate repairs in 2009, 132 immediate conditions were repaired in 2010 and 255 in 2011. The number of scheduled conditions repaired was 1,027 in 2010 and 1,219 in 2011; there were 266 scheduled repairs in 2009.

Figure 4: Repairs Made by Pipeline Operators in High Consequence Areas Resulting from Assessments from 2004 to 2009



Source: GAO analysis of PHMSA data.

Note: According to PHMSA, repairs reported in one year may not have been identified by assessments performed in that same year. There is a potential lag between when pipeline miles were assessed, the repair condition identified, and when the condition was actually repaired. The lag between assessment and repair is likely greater for scheduled repairs than for immediate repairs.

During this period—2004 through 2011—PHMSA also collected data on the frequency of incidents, failures, and leaks in high consequence areas.²³ The average number of incidents in high consequence areas—

²³PHMSA defines “incidents” as the release of gas from a pipeline that results in: a death or personal injury requiring in-patient hospitalization, estimated property damage of \$50,000 or more, unintentional estimated gas loss of three million cubic feet or more, or an event that is significant in the operator’s judgment. “Leaks” are defined as the unintentional escape of gas from a pipeline that is not reportable as an incident. PHMSA defines a “failure” using the industry consensus standard developed by the American Society of Mechanical Engineers (ASME B31.8S), which classifies a failure as a part in service that has become inoperable, is still operable but is incapable of satisfactory performance, or that has deteriorated to the point of being unreliable or unsafe for continued use. See 49 C.F.R. § 191.3 and 75 Fed. Reg. 72878 (Nov. 26, 2010).

the most serious of the three events because they can result in fatalities, injuries, or significant property damage—was 8 per year. When incidents in high consequence areas occur, they can have a significant impact in terms of lives lost, injuries, and property damage, as seen with the incident, noted earlier, in San Bruno, California.

PHMSA Data Alone Cannot Be Used to Determine a Maximum Reassessment Interval

Individual pipeline operators can use data collected through baseline assessments and reassessments to determine the appropriate reassessment interval for pipeline segments on their systems, but using these data once they have been aggregated to determine a national maximum reassessment interval is not feasible. Per PHMSA's regulations,²⁴ operators use information on risks specific to their pipeline and changes in anomalies previously identified to determine the appropriate reassessment interval for their pipeline segments in high consequence areas. For example, an operator told us that the company calculates reassessment intervals for pipeline segments in high consequence areas using baseline assessment and reassessment data (when available) to determine the remaining strength of an anomaly and a corrosion growth rate. Based on these calculations, corrosion should not grow to unsafe levels before the next reassessment. Pipeline operators report data to PHMSA that include the miles assessed in high consequence areas, conditions repaired within high consequence areas, and the tools used to conduct assessments. These data are reported as a summary of all pipeline miles for that company. Operators with both interstate and intrastate pipelines as well as those transporting different gas products are required to report on each system separately. As a result, the data collected by PHMSA are highly aggregated and do not allow comparison of a single pipeline segment over time, or the determination of a national maximum reassessment interval.

We were asked to compare the number of anomalies noted in PHMSA's baseline assessment data with its reassessment data as part of the mandate for this report in the Pipeline Safety, Regulatory Certainty, and

²⁴49 C.F.R. § 192.939.

Job Creation Act of 2011.²⁵ As described below, the assessment repair data collected by PHMSA lack the detail and completeness to make this comparison:

- PHMSA’s data do not separate conditions repaired that were identified from baseline assessments from those identified by reassessments.²⁶ Beginning with the 2010 annual report, PHMSA has used a data collection form that does not require pipeline operators to differentiate conditions repaired based on whether the condition was identified during a baseline assessment or a reassessment. A PHMSA official told us that given the quantity of data pipeline operators are already required to provide to PHMSA, asking them to report conditions as either identified during baseline assessments or reassessments would significantly increase the reporting burden. Also, as pipeline operators begin their second round of reassessments, the data will not identify repairs as coming from the first, second, or later rounds of reassessments. The lack of detail in PHMSA’s data will make it impossible to compare—amongst all gas transmission pipeline operators or for a specific pipeline system—the number of repairs identified during baseline assessments to those identified during reassessments. Therefore, looking solely at PHMSA’s data, an observer could not tell whether conditions repaired have increased or decreased as operators conduct initial and subsequent reassessments.
- Even if repair data were separated based on whether the condition repaired was identified during a baseline assessment or reassessment, the first round of reassessments in high consequence

²⁵PHMSA defines an “anomaly” as a deviation from the original configuration of the pipeline, such as a crack, change in wall thickness due to metal loss, or a dent or gouge in the pipe wall. PHMSA uses the term “condition” to describe anomalies that require, for example, immediate or scheduled repair. Since PHMSA’s data focuses on conditions or conditions repaired, we use these terms to refer to anomalies. See 49 C.F.R. §192.933(a), (c), (d)(1), (d)(2), and (d)(3).

²⁶PHMSA’s annual report for gas transmission pipelines asks pipeline operators to report the total number of conditions (meeting the definition of either an immediate repair condition, a one-year condition, a monitored condition, or other scheduled conditions as defined in regulation) repaired in that calendar year within a high consequence area pipeline segment by the type of assessment tool used (e.g., in-line inspection, direct assessment, or other assessment methods).

areas may not be complete until the end of 2019.²⁷ A comparison of the number of critical repairs identified during baseline assessments and reassessments would not be possible until these reassessments are complete.

Further, even if the repair data from baseline assessments and reassessments could be compared, these data are not sufficient to determine an appropriate maximum reassessment interval—such as the 7-year reassessment interval established in the Pipeline Safety Improvement Act of 2002—for all operators for several reasons, including those listed below:

- A decrease or increase in the number of conditions repaired would not necessarily indicate the appropriateness of the 7-year reassessment requirement. For example, according to the American Society of Mechanical Engineers (ASME), a decline in the number of repairs per mile would indicate the effectiveness of a pipeline operator's integrity management plan and not that of the reassessment interval itself.
- As mentioned above, the data reported to PHMSA are highly aggregated. As a result, it is not possible to perform the type of analysis at the national level that pipeline operators use to determine reassessment intervals for an individual pipeline segment. For example, calculating a corrosion growth rate using assessment data is one way that pipeline operators can determine the appropriate reassessment interval for a pipeline segment. This calculation requires information about the history, condition, environment, and the characteristics of individual anomalies found on that individual pipeline segment. PHMSA's assessment data do not have that level of necessary detail, so they cannot be used to determine an appropriate maximum reassessment interval for the entire gas transmission pipeline system in the United States. Instead, PHMSA's data can provide descriptive information about how much pipeline mileage operators are assessing and how many repairs are being made.

While the repair data collected by PHMSA are not sufficient to determine an appropriate maximum reassessment interval for all pipelines in the United States, an industry standard setting organization has developed maximum reassessment intervals of 10, 15, or 20 years that are widely

²⁷Since gas transmission pipeline operators had until December 2012 to finish baseline assessments, the initial round of reassessments may not be complete until 7 years later, or December 2019.

accepted as balanced and transparent. As we reported in 2006,²⁸ ASME developed an industry consensus standard—subsequently approved by the American National Standards Institute²⁹—on maximum reassessment intervals for all safety risks (including corrosion damage) that PHMSA incorporated into its regulations. ASME based this standard on, among other things, (1) the experience and expertise of engineers, consultants, operators, local distribution companies, and pipeline manufacturers; (2) more than 20 technical studies conducted by the Gas Technology Institute, ranging from pipeline design factors to natural gas pipeline risk management; and (3) other industry consensus standards, including the National Association of Corrosion Engineers standards, on topics such as corrosion. 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 1995.³⁰ 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.

²⁸GAO, *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).

²⁹The American National Standards Institute is a private, nonprofit 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.

³⁰Pub. L. No. 104-113, §12, 110 Stat. 782 (1996).

The 7-Year Reassessment Requirement Provides a Safeguard, but Is Not Fully Consistent with Risk-Based Practices

Maximum Reassessment Intervals Provide a Safeguard

Maximum reassessment intervals—such as the 7-year reassessment requirement—provide a safeguard and allow regulators and operators to identify and address problems on a continual basis. The 7-year reassessment requirement as well as the reassessment intervals noted in the industry consensus standards represent the maximum number of years between reassessments. If pipeline conditions dictate more frequent reassessments, then pipeline operators must perform reassessments more frequently in order to comply with PHMSA’s integrity management regulations. Both the 7-year reassessment requirement and the maximum reassessment intervals noted in the industry consensus standards are likely to identify problems before they result in leaks or ruptures. For example, according to the industry consensus standards, it typically takes longer than the 10, 15, or 20 years specified in the standards for corrosion problems to result in a leak or rupture. Because the 7-year reassessment requirement is a more frequent interval than those in the industry consensus standards, it provides greater assurance that operators are regularly monitoring their pipelines to identify and address threats before they result in a leak or rupture.

Regulators and operators we spoke with indicated that a maximum reassessment interval should exist and saw benefits to conducting periodic assessments of gas transmission pipelines. Regulators—both at the federal and state levels—told us that overseeing a maximum reassessment interval is rather straightforward. For example, an inspector can use operators’ records to verify relatively easily whether the operator completed an assessment on time. Operators we spoke with also support maximum reassessment intervals, telling us that in performing baseline assessments and reassessments they have obtained valuable knowledge of the condition of their pipeline systems, and that a maximum

reassessment interval can provide a safeguard to compel poor performing operators to improve the integrity of their pipeline systems.

The 7-Year Reassessment Requirement Is Not Fully Consistent with Risk-Based Practices

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 is based on risk-based management practices. For example, it requires operators to integrate information from various sources, such as assessments, to identify the risks specific to their pipelines. To prioritize risks for resource allocation, the gas integrity management program focuses on high consequence areas and required operators to assess the riskiest segments of their pipelines first. Our past work has shown the benefits of risk-based management, including the integrity management program.³¹ For instance, we reported in 2006 that the integrity management program benefits public safety by supplementing existing safety requirements with risk-based management principles that focus on safety risks in high consequence areas.

However, the 7-year reassessment requirement—which was established by the Pipeline Safety Improvement Act of 2002 and is just one component of the gas integrity management program—is not fully consistent with risk-based management practices. For example, the 7-year reassessment requirement does not permit operators to apply the information that they have collected from their assessments: even though operators must determine an appropriate reassessment interval based on the threats facing their pipelines in high consequence areas, they must reassess those pipelines at least for corrosion threats every 7 years regardless of the risks identified. While operators can currently use data—such as pipeline conditions and other information learned from previous assessments—to determine that more frequent assessments than every 7 years are required (e.g., every 5 years), operators cannot

³¹GAO, *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); and *Natural Gas Pipeline Safety: Integrity Management Benefits Public Safety, but Consistency of Performance Measures Should be Improved*, [GAO-06-946](#) (Washington, D.C.: Sept. 8, 2006).

bypass the 7-year reassessment requirement if they have data that shows reassessment intervals longer than 7 years are justified (e.g., every 10 years). Rather, operators that choose to establish reassessment intervals beyond 7 years must still conduct some type of reassessment at least every 7 years in order to comply with the 2002 act. PHMSA officials told us that the 7-year reassessment requirement does not take into account risk, and while it may be an appropriate interval length for some pipeline systems, it is too short or too long for other systems.

In contrast to these regulations, there are no statutory requirements that limit risk-based reassessment intervals for operators of a different type of pipeline, that of hazardous liquids. Under PHMSA's regulations for the hazardous liquid integrity management program, operators must perform assessments of their pipelines within high consequence areas following a maximum reassessment interval. This reassessment interval—which, unlike the gas transmission pipeline reassessment interval, was established by a PHMSA rulemaking using a data analysis³²—can be extended if an operator can provide an engineering basis to do so; that is, operators have the ability to use the information learned from prior assessments and other efforts to identify and assess the risks facing its pipelines and determine that a longer reassessment interval is justified. Because the 7-year reassessment requirement for gas transmission pipelines was established by statute and not in a PHMSA rulemaking, PHMSA does not have the authority to modify this requirement without congressional action.

In 2006, we reported that most of the operators we contacted preferred that reassessment intervals be based on the conditions and characteristics of the pipeline segment. In general, the industry associations we spoke with for this report also preferred risk-based reassessment intervals instead of the current 7-year reassessment requirement. In addition, 21 of the 27 operators we spoke with for this report indicated that they prefer a risk-based reassessment interval requirement. According to some of these operators, complying with the

³²Per PHMSA's regulations, hazardous liquid pipelines have a maximum reassessment interval of 5 years. This reassessment interval was determined, in part, through an analysis of available data. PHMSA established integrity management requirements 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. Prior to enactment of the Pipeline Safety Improvement Act of 2002, PHMSA was exploring a rulemaking for integrity management for gas transmission pipelines.

current 7-year reassessment requirement without the ability to use risk-based reassessment intervals beyond 7 years may not be an efficient use of their resources. For example, some operators told us that if they could reassess their pipeline segments less frequently than every 7 years without negatively impacting safety, they could potentially devote more resources to other safety tasks.

PHMSA's gas transmission integrity management regulations include provisions that could make reassessments more risk-based, but these efforts have not seen widespread use, primarily due to the 2002 act's 7-year reassessment requirement.

- PHMSA's regulations permit operators to use confirmatory direct assessment to comply with the 2002 act. Operators that choose to use confirmatory direct assessment are those that have established reassessment intervals greater than 7 years but no more than those noted in the industry consensus standards. These operators perform a confirmatory direct assessment at year 7 to look for corrosion threats only, followed by a reassessment at the interval the operator established for all threats facing the pipeline. According to PHMSA officials, confirmatory direct assessment was included in the regulations to better align with risk management principles. However, of the 27 operators with whom we spoke, only 5 told us that they completed or planned to conduct confirmatory direct assessment. According to some of the operators we spoke with, confirmatory direct assessment—which looks for corrosion damage only—can be just as costly and time-consuming as performing a reassessment for all safety risks and, therefore, the operators chose to perform a reassessment at the 7-year mark instead. Most of the regulators we spoke with—both at the federal and state levels—also noted that operators are generally not using confirmatory direct assessment.
- PHMSA's regulations allow operators with 'exceptional performance' to deviate from some of the requirements of the integrity management regulations.³³ These operators must have completed at least two assessments (i.e., a baseline assessment and a reassessment) and have remediated all anomalies found in the most recent assessment. An operator satisfying all of the exceptional performance criteria is generally permitted to deviate from most integrity management regulations. However, in order to comply with the 2002 act and

³³49 C.F.R. § 192.913.

PHMSA's regulations, the operator must still perform a confirmatory direct assessment at least every 7 years. None of the operators we spoke with are pursuing the exceptional performance option, with most indicating that because they must complete a confirmatory direct assessment to identify corrosion problems every 7 years, this option holds little, if any, benefit.

Implementing Risk-Based Reassessment Intervals beyond 7 Years Could Exacerbate Current Challenges and Would Benefit from More Information on Resource Requirements

Changes to the 7-Year Reassessment Requirement Requires Congressional Action and Could Exacerbate Current Issues with Reviewing and Justifying Reassessment Intervals

Although PHMSA generally agreed in the past that risk-based standards would allow operators to better tailor reassessments to pipeline threats, PHMSA cannot change the current 7-year reassessment requirement unless congressional action occurs because the requirement is in statute. The reassessment requirement is in the regulation pursuant to the requirement in the Pipeline Safety Improvement Act of 2002. In 2006, we recommended that this statutory requirement be amended to permit operators to reassess at intervals based on risk factors, technical data, and engineering analyses.³⁴

In addition to requiring a statutory change, PHMSA officials noted that a number of current challenges could potentially be exacerbated by implementing risk-based reassessment intervals. For instance, inspecting and evaluating risk-based reassessment intervals beyond 7 years could

³⁴[GAO-06-945](#).

create additional workload, staffing, and expertise challenges for regulators, such as PHMSA and state pipeline safety offices, for example:

- PHMSA officials told us that allowing all operators to participate in risk-based reassessment intervals beyond 7 years could add significantly to the agency's workload in terms of inspecting operators' integrity management programs, including review of their calculated reassessment intervals. For instance, these evaluations could require inspectors to spend more time and resources than currently, which could affect the number of inspections conducted overall. Moreover, PHMSA has already experienced some workload problems with inspections, which could be worsened by allowing operators to use risk-based reassessment intervals beyond 7 years. For example, in 2012, the Department of Transportation's Office of the Inspector General reported that PHMSA has recently accumulated a backlog of integrity management inspections for hazardous liquid operators, caused in part by the agency redirecting resources to fulfill other inspection requirements.³⁵ In response, beginning in 2013, the agency will implement a new approach to inspections, called integrated inspections,³⁶ where an inspector may use data and information about a specific operator and pipeline system to custom-build a list of regulatory requirements to evaluate during inspection. For these integrated inspections, integrity management requirements would be one of several regulatory requirements inspectors could choose to focus on. However, the Inspector General's report noted that PHMSA's proposed schedule to implement a number of enhancements to its inspection program is ambitious and challenging,

³⁵U.S. Department of Transportation Office of Inspector General, *Hazardous Liquid Pipeline Operators' Integrity Management Programs Need More Rigorous PHMSA Oversight*, Report no. AV-2012-140, (June 18, 2012). According to the Inspector General's report on hazardous liquids, PHMSA would have needed to complete 49 integrity management inspections in 2012 to clear its backlog; however, the agency averages only around 22 integrity management inspections per year.

³⁶The Office of Pipeline Safety began pilot testing integrated inspections in 2008. Integrated inspections are a data-driven process allowing the Office to focus inspection resources on the regulatory provisions addressing the greatest identified risks. Integrated inspections would contain integrity management inspection requirements, according to PHMSA officials. According to PHMSA's gas integrity management inspection manual, which includes inspection protocols, the purpose of the inspection is not to perform a quality check of every integrity related activity. Instead, inspectors will typically perform an inspection of selected operator records sufficient in breadth and depth to give the inspection team adequate understanding of the degree of compliance.

and until PHMSA successfully completes the transition, the agency may not be able to ensure sufficient and consistent oversight of all integrity management programs.

- Officials from state pipeline safety offices we met with noted potential concerns with staffing and training to effectively evaluate risk-based reassessment intervals. For example, some state pipeline safety officials suggested that they would need dedicated staff to evaluate operators' results and analyses, while other state officials cited the current difficulty with enrolling in PHMSA training courses due to long waiting lists. Also, some operators we interviewed expressed concern that inspectors from state pipeline safety offices may lack sufficient training to review these analyses. For example, although state officials currently inspect operators' integrity management programs, some operators told us that inspectors do not typically challenge their reassessment interval calculations.
- Regulating risk-based reassessment intervals beyond 7 years could be particularly challenging for PHMSA and state pipeline safety offices because there is a lack of guidance for operators to perform risk modeling. As a result, operators could use a variety of methodologies to calculate appropriate reassessment intervals for pipeline systems and even individual segments. The level of detail and review required by regulators overseeing these operators would vary depending on the sophistication of the operators' analyses.

While current regulations require operators to use engineering and risk analyses to determine the frequency at which reassessments must be conducted, operators could face additional challenges in justifying and calculating risk-based reassessment intervals beyond 7 years. Some operators told us that risk-based reassessment intervals beyond 7 years would likely be more labor-intensive and data-driven than the current regulatory environment. For example, operators would likely have to provide PHMSA more analyses to justify their calculated reassessment intervals than currently. Based on our interviews, operators appear to vary in the extent to which they currently calculate reassessment intervals and use the results of the data analyses, for example:

- Some operators we spoke with told us that they perform a less rigorous determination of their reassessment intervals and default to the 7-year interval if they determine that there are no problems with their pipelines. Also, one operator told us that unless evidence of corrosion is found on the pipeline segment, the operator does not perform a comprehensive calculation of the reassessment interval.
- Some operators we spoke with calculated reassessment intervals resulting in 7 years, but still chose to reassess their pipelines more

frequently than their calculations due to identified conditions such as pipeline coating issues. While such a decision prioritizes the safety of the pipeline, it also illustrates some of the potential subjectivity involved with reassessment interval calculations, which may have accounted for such conditions, but did not ultimately determine a shorter interval in the analysis. For example, some PHMSA officials told us that oftentimes there is more than one correct conclusion based on pipeline data and some operators will choose a more conservative approach than others and vice versa. Further, some technical experts told us that risk-based reassessment intervals would require a higher level of skill and analysis beyond some operators' current capabilities, thus forcing the operator to seek the assistance of contractors.

As a result, the challenges operators currently have with justifying and calculating reassessment intervals, partly because of a lack of guidance from PHMSA, could be further affected if operators are to use these types of analyses to justify risk-based reassessment intervals beyond 7 years. Without guidance for operators to use in determining and calculating reassessment intervals, operators may use a range of approaches for determining the relevant risks to their systems, which could then create potential challenges for regulators with reviewing risk-based reassessment intervals beyond 7 years and ensuring oversight of these pipelines.

PHMSA Has Previously Considered an Approach to Implementing Risk-Based Reassessment Intervals beyond 7 Years, but More Information on Resource Requirements Is Needed

In 2008, PHMSA provided a detailed statement at the request of Congress to explain how the agency would establish and enforce risk-based criteria for extending the 7-year reassessment interval.³⁷ According to PHMSA's proposal, it would retain the current 7-year reassessment requirement, but allow for the use of risk-based reassessment intervals on a case-by-case basis where justified. Congress did not take any action to address this proposal as a result of the 2008 report,³⁸ and PHMSA has neither reviewed nor updated its 2008 report to determine whether that report's conclusions remain valid. However, PHMSA's proposal outlined a number of steps to establish a process permitting the use of risk-based reassessment intervals beyond 7 years, for example:

- First, PHMSA would establish via rulemaking risk-based criteria that operators must meet to warrant extending their reassessment intervals beyond 7 years.³⁹
- Second, interested operators would have to notify PHMSA (or a state pipeline safety office for an intrastate transmission pipeline) one year in advance of the scheduled reassessment and submit information demonstrating their conformance with the criteria before using risk-based reassessment intervals beyond 7 years. As shown in table 1, one potential criterion could require some operators to conduct assessments using in-line inspection or hydrostatic testing (see appendix II for a longer list of draft criteria provided by PHMSA).

³⁷Pipeline and Hazardous Materials Safety Administration, *Gas Transmission Pipeline Integrity Management Assessment: Proposed Reassessment Interval Extension Review*, (Apr. 15, 2008).

³⁸The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, however, did allow for a 6-month extension of the 7-year reassessment requirement if the operator submits written notice to the Secretary with sufficient justification of the need for the extension, subject to the limits of the waiver process under 49 U.S.C. § 60109(c)(5). Pub. L. No. 112-90, §5(e), 125 Stat. 1904, 1908 (codified at 49 U.S.C. § 60109(c)(3)(B)).

³⁹PHMSA also proposed that if the statutory requirement was not amended, the agency could use the specific authority granted by Congress for operators to apply for a waiver (49 U.S.C. § 60109(c)(5)). For example, PHMSA would issue special permits to operators, allowing them to extend the assessment interval, based on the conditions of the permit. However, according to PHMSA's regulations for gas transmission integrity management, the agency can only grant waivers of the 7-year maximum reassessment interval either to maintain local product supply or due to the lack of internal inspection devices. As a result, PHMSA's own regulations do not allow for additional types of waivers. 49 C.F.R. § 192.943.

Table 1: Examples of Potential Criteria for Risk-Based Pipeline Reassessment Intervals

Potential criteria examples

- If the pipeline operates at pressures that are greater than or equal to 30 percent of specified minimum yield strength it must have been assessed using in-line inspection or hydrostatic testing.
 - Few or no significant corrosion repairs have been made in the covered segment since the last integrity assessment.
 - Causes of previously identified significant corrosion defects have been corrected.
 - Pipeline is coated and cathodically protected (a technique to reduce the corrosion of a metal surface) and be in good condition.
 - No history of pipeline cracking due to the combined influence of stress and a corrosive environment.
 - Assumed corrosion growth rate is justified and supports the longer reassessment interval. Calculations of the remaining time frame before pipeline failure are conservative and demonstrate safety for an extended interval.
 - Pipeline must have been constructed after 1970 unless demonstration of good condition is provided.
 - Environmental conditions in which the affected pipeline segment is located must not be unusually conducive to corrosion.
-

Source: PHMSA.

Note: As noted above, PHMSA has neither reviewed nor updated its 2008 report to determine whether that report's conclusions remain valid. For example, according to PHMSA, the 30 percent of specified minimum yield strength figure shown in the first criteria above does not reflect PHMSA's current regulatory requirements.

- Third, PHMSA would review all the notifications to determine whether the criteria in the rule have been met.⁴⁰ For example, operators would need to demonstrate through analyses and documentation that their pipeline segments meet each criterion or provide substantial justification that any failure to meet a criterion does not increase the risk of corrosion in the segment. PHMSA would also consider in its review the specific location of the pipeline segments, the potential consequences if an accident were to occur at that location, and the compliance and overall performance history of the operator.

PHMSA officials expected that operators of some types of pipelines would be more likely to use risk-based reassessment intervals beyond 7 years than others. For example, PHMSA cited operators that have demonstrated that their pipe is sound and that their engineering and risk analysis do not indicate the likelihood of time-dependent integrity problems occurring during a reassessment interval beyond 7 years. Although operators support the idea of using risk-based reassessment intervals beyond 7 years, it is not clear how many operators would be

⁴⁰PHMSA conducted a public meeting in January 2008 to describe the criteria it would use to gauge the suitability of using risk-based reassessment intervals beyond 7 years where justified. According to PHMSA's proposal, the agency would develop additional detailed guidance concerning the information necessary to demonstrate conformance with the criteria.

able to meet the potential criteria established by PHMSA, and PHMSA officials could not estimate the number either. For example, not all operators can conduct assessments using in-line inspection or hydrostatic testing, which is one of PHMSA's proposed criteria for using risk-based reassessment intervals. According to the proposal, operators would have to meet each of the criteria. As a result, the mileage of pipelines that would be affected by allowing risk-based reassessment intervals beyond 7 years is currently unknown.

In light of the uncertain potential effect on resources and expertise for both regulators and operators, an effort to implement risk-based reassessment intervals beyond 7 years may benefit first from PHMSA obtaining additional information regarding the resource requirements needed prior to a rule change, such as how the Office of Pipeline Safety initially established integrity management regulations. For example, the Accountable Pipeline Safety and Partnership Act of 1996 directed the Office of Pipeline Safety to establish a demonstration program to test a risk management approach to pipeline safety.⁴¹ Under the program envisioned by the legislation, the Secretary sought voluntary participation by interstate natural gas and hazardous liquid transmission operators in good standing to demonstrate company-specific risk management plans. The Secretary then completed a rulemaking that outlined the demonstration plan's elements and provided opportunities for full public participation in the process. As a result, partly on the basis of the agency's experience with the risk management demonstration program, the agency moved forward with a new regulatory approach, known as integrity management. Similarly, as noted above, PHMSA produced a report at the request of Congress explaining how the agency would establish and enforce risk-based criteria for extending the 7-year reassessment interval. In effect, efforts such as these allowed the agency to obtain preliminary results and information on the proposed rule such as the potential benefits and impacts under a variety of conditions before making a change.

⁴¹Pub. L. No. 104-304, § 5, 110 Stat. 3793, 3798 (1996).

Conclusions

Gas transmission pipeline assessments and reassessments have resulted in critical repairs being made. While the 7-year reassessment requirement has provided a safeguard by helping to identify these problems before they cause leaks or ruptures, the prescriptive 7-year reassessment requirement is not fully consistent with the characteristics of risk-based management promoted by the Pipeline Safety Improvement Act of 2002. PHMSA has generally agreed that risk-based reassessment intervals would allow operators to better tailor reassessments to pipeline threats and operators support this concept. Risk-based reassessment intervals beyond 7 years would allow operators to use the information they have collected about their pipeline systems to focus resources on areas of greatest importance.

PHMSA drafted a process to establish and enforce risk-based criteria for the potential use of risk-based reassessment intervals in 2008. While this process would be more consistent with risk management practices, permitting operators to use risk-based reassessment intervals beyond 7 years would not be without challenges, even if justified using an engineering basis. First, Congress would have to amend the statutory requirement mandating the 7-year reassessment interval. In 2006, we recommended that this statutory requirement be amended to permit operators to reassess at intervals based on risk factors, technical data, and engineering analyses. If Congress were to amend the statute, both federal and state regulators as well as operators anticipate that overseeing and determining risk-based reassessment intervals beyond 7 years may create workload, staffing, and expertise challenges over what is currently required. Further, there is a lack of guidance to assist regulators and operators in developing the risk models currently used to calculate reassessment intervals. Without such guidance, operators could use a range of approaches for determining the relevant risk to gas transmission pipelines, potentially creating challenges with reviewing and justifying reassessment intervals.

Given these potential challenges, more information might help decision-makers better understand the resource requirements needed in allowing risk-based reassessment intervals beyond 7 years. In this context, conducting a study or developing a legislative proposal for a pilot program, in consultation with Congress, to examine the impact on regulators and operators from the use of risk-based reassessment intervals beyond 7 years could help stakeholders—including regulators, operators, and decision-makers—determine the resource demands of inspecting and evaluating these efforts. A full evaluation of the challenges to implementing risk-based reassessment intervals beyond 7 years and

their associated resource requirements could help to identify the most prudent and effective way to implement risk-based reassessment intervals. Such an evaluation could help to ensure that the challenges regulators and operators claim they may face from this change would not negatively affect safety. Further, a study—similar to the 2008 report PHMSA prepared at the request of Congress and incorporating lessons learned since publication of that report—or a legislative proposal for a pilot program—similar to the one used in developing the integrity management program—could allow regulators to develop guidance on calculating risk-based reassessment intervals as well as determine the impact of these reassessment intervals. As the debate about the use of risk-based reassessment intervals continues, it is clear that more information is needed to further the understanding and discussion about how to address the potential challenges to using risk-based reassessment intervals beyond 7 years before any change occurs.

Recommendations for Executive Action

To improve how operators calculate reassessment intervals, we recommend that the Secretary of Transportation direct the Administrator for the Pipeline and Hazardous Materials Safety Administration to develop guidance for operators to use in determining risks and calculating reassessment intervals.

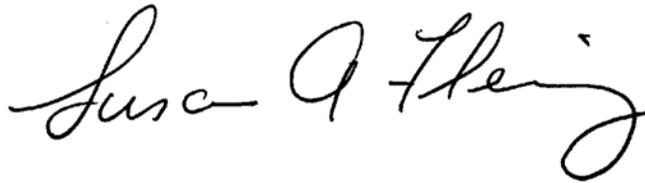
To better identify the resource requirements needed to implement risk-based reassessment intervals beyond 7 years for gas transmission pipelines, we recommend that the Secretary of Transportation direct the Administrator for the Pipeline and Hazardous Materials Safety Administration to collect information on the feasibility of addressing the potential challenges of implementing risk-based reassessment intervals beyond 7 years, for example by preparing a report or developing a legislative proposal for a pilot program, in consultation with Congress, that studies the impact to regulators and operators of a potential rule change.

Agency Comments

We provided the Department of Transportation with a draft of this report for review and comment. The department did not agree or disagree with the recommendations, but provided technical comments that we incorporated as appropriate.

We are sending copies of this report to relevant congressional committees, the Secretary of Transportation, and other interested parties. In addition, this report will also be available at no charge on GAO's website at <http://www.gao.gov>.

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

A handwritten signature in black ink that reads "Susan A. Fleming". The signature is written in a cursive style with a large, looping 'S' and 'F'.

Susan A. Fleming
Director, Physical Infrastructure Issues

Appendix I: Objectives, Scope, and Methodology

Our work for this report focused on gas transmission pipelines in high consequence areas and the requirement to assess these pipeline segments at periodic intervals. In particular, this report examines: (1) the extent to which the Pipeline and Hazardous Materials Safety Administration's (PHMSA) assessment data provides information on repairs made and the appropriateness of the 7-year reassessment requirement, (2) the impact of the 7-year reassessment requirement on regulators and operators, and (3) the potential challenges of implementing risk-based reassessment intervals beyond 7 years.

To address the extent to which PHMSA's assessment data provides information on repairs and the appropriateness of the 7-year reassessment requirement, we reviewed PHMSA's regulations, prior GAO reports, and PHMSA data on gas transmission pipelines. We analyzed the data reported to PHMSA by pipeline operators on, among other things, age and operating pressure of transmission pipelines; pipeline miles assessed; tools used to conduct assessments; immediate and scheduled conditions found during assessments and subsequently repaired; and incidents, leaks, and failures on gas transmission pipelines in high consequence areas.

We used two PHMSA data sources in our data analysis: the Gas Integrity Management Semi-Annual Performance Measures Reports from 2004 through 2009 and the Annual Reports on Natural and Other Gas Transmission and Gathering Pipeline Systems from 2010 and 2011. From 2004 to 2009, PHMSA collected information on miles assessed, incidents, leaks, and failures in high consequence areas using the Gas Integrity Management Semi-Annual Performance Measures Report. Through this report, PHMSA collected data on baseline assessments and started collecting data on reassessments in 2008. In 2010, PHMSA discontinued the Gas Integrity Management Semi-Annual Performance Measures Report and merged it with the Annual Report on Natural and Other Gas Transmission and Gathering Pipeline Systems. The updated Annual Report on Natural and Other Gas Transmission and Gathering Pipeline Systems added questions on pipeline miles that were baseline assessed and reassessed; tools used to conduct assessments; conditions identified and repaired as a result of assessments; and incidents, leaks, and failures in high consequence areas. One important change in the updated Annual Report was PHMSA's new approach to documenting conditions and repairs identified by baseline assessments and reassessments. Prior to 2010, pipeline operators reported the number of repairs made on pipelines to fix problematic conditions identified by the assessments—a single repair could mitigate multiple problems. For 2010 and later,

pipeline operators were required to report the number of repaired conditions. Since operators have to report the actual number of problems found and repaired, PHMSA expected the number of reported repairs to spike. Due to this reporting change, we cannot compare repair data from 2004 to 2009 to repair data reported in 2010 and later. To assess the reliability of PHMSA's gas transmission pipeline data, we spoke with agency officials about data quality control procedures and reviewed relevant documentation. We determined that the data were sufficiently reliable for the purposes of this report, specifically to provide background information and to describe repairs made in high consequence areas. To ensure the accuracy of our data analysis, we internally reviewed our calculations and shared preliminary results with PHMSA to ensure that we analyzed its data appropriately.

To determine the impact of the 7-year reassessment requirement on regulators and operators, we reviewed relevant legislation and PHMSA regulations on integrity management. We also interviewed federal and state regulators, industry associations, gas transmission pipeline operators, pipeline safety advocacy and environmental groups, research firms, a state regulatory association, and technical experts. We selected 27 pipeline operators to interview based on our review of PHMSA data, specifically looking for pipeline operators with gas transmission pipeline miles in high consequence areas. We then divided pipeline operators into six groups based on their mileage in high consequence areas and whether they had conducted reassessments. We chose 3 to 5 operators from each of the six groups, with the goal of ensuring diversity across these and several other characteristics, including the number of recent incidents caused by corrosion and their geographic location. The information obtained in these interviews is not generalizable to the entire population of pipeline operators. We also selected a non-generalizable sample of eight state pipeline safety offices using PHMSA data to, for example, identify states with relatively high pipeline mileage while also achieving geographic diversity. Five of the states we spoke with serve as interstate agents for PHMSA.⁴² To learn about the operations of a gas transmission pipeline and the logistics of conducting an assessment, we made two site visits to view a pipeline under construction in Manassas,

⁴²PHMSA may authorize states to act as its agent through an agreement to inspect interstate pipelines, but PHMSA retains responsibility for enforcement of regulations. PHMSA currently has agreements with nine state agencies to act as interstate agents for gas transmission pipelines.

Virginia, and to view an in-line inspection tool being used on a pipeline in Rockville, Maryland.

To determine the potential challenges of implementing risk-based reassessment intervals beyond 7 years, we reviewed PHMSA documents. We also questioned federal and state regulators, industry associations, gas transmission pipeline operators, pipeline safety advocacy and environmental groups, research firms, a state regulatory association, and technical experts on the extent pipeline operators use risk to determine reassessment intervals under the current system, as well as how expanding the use of risk-based reassessment intervals beyond 7 years would impact operators and regulators. We collected additional data from three pipeline operators on their experiences in calculating reassessment intervals and conducting reassessments. We selected these three pipeline operators by using PHMSA data to identify gas transmission pipeline operators with different ranges of mileage in high consequence areas. We then selected operators that had completed at least some reassessments and looked for diversity in the following categories: geographic location, number of pipeline repairs, and tools used to complete assessments.

Organizations Contacted

We interviewed representatives from each of the following organizations:

Federal Government

- Department of Transportation, Pipeline and Hazardous Materials Safety Administration
 - Headquarters
 - Eastern Regional Office
 - Central Regional Office
 - Southern Regional Office
 - Southwest Regional Office
 - Western Regional Office
- National Transportation Safety Board

State Pipeline Safety Offices

Arizona Office of Public Safety
California Public Utilities Commission
Michigan Public Service Commission
New York State Department of Public Service

North Carolina Utilities Commission
Public Utilities Commission of Ohio
Railroad Commission of Texas
West Virginia Public Service Commission

Industry Associations

American Gas Association
Inline Inspection Association
Interstate Natural Gas Association of America

Pipeline Operators

Alaska Pipeline Company
American Midstream (Tennessee River), LLC
ARCO Western Gas Pipeline Company
Atmos Pipeline—Texas
Colonial Gas Company (Lowell Division)
Columbia Gas of Ohio, Inc.
Gas Transmission Northwest Corporation
Gulfstream Natural Gas System, LLC
Hampshire Gas Company
KO Transmission Company
Massachusetts Wholesale Electric Company
MidContinent Express Pipeline LLC
Mojave Pipeline Operating Company
National Fuel Gas Supply Corporation
Northwest Pipeline Corporation
Ohio Valley Gas Corporation
Peco Energy Company
Questar Gas Company
San Diego Gas and Electric Company
Silicon Valley Power
Southcross Gulf Coast Transmission, LTD
Tennessee Gas Pipeline Company
Texas Eastern Transmission LP
UCAR Pipeline, Inc.
Viking Gas Transmission Company
Washington Gas Light Company
Williams Gas Pipeline—Transco

Pipeline Safety Advocacy and Environmental Groups

Common Ground Alliance
Pipeline Safety Trust
The Wilderness Society

Research Firms

Gas Technology Institute
Pipeline Research Council International

State Regulatory Association

National Association of Pipeline Safety Representatives

Technical Experts

American Society of Mechanical Engineers
Kiefner and Associates, Inc.
National Association of Corrosion Engineers
WKM Consultancy

Appendix II: Potential Criteria for Risk-Based Reassessment Intervals

In 2008, Congress requested that the Pipeline and Hazardous Materials Safety Administration (PHMSA) provide a detailed statement to explain how the agency would establish and enforce risk-based criteria for extending the 7-year reassessment interval. As part of that request, PHMSA drafted potential criteria that operators would have to meet in order to use risk-based reassessment intervals beyond 7 years.⁴³ PHMSA noted that the criteria may be further refined as potential rulemaking proceeds. The draft criteria include:

- If the pipeline operates at pressures that are greater than or equal to 30 percent of specified minimum yield strength, it must have been assessed using in-line inspection or hydrostatic testing.
- Most recent in-line inspection assessment shows pipeline to be in good condition. Few conditions meeting immediate repair criteria were found and the causative corrosion mechanisms have been identified and addressed.
- Most recent pressure test meets integrity management requirements and resulted in few leaks/failures or pressure reversals.
- Few or no significant corrosion repairs have been made in the covered segment since the last integrity assessment.
- Causes of previously identified significant corrosion defects have been corrected.
- No history of selective seam corrosion (a specialized form of corrosion associated with older pipelines), or microbiologically induced corrosion (a mode of corrosion incorporating microbes that react and cause the corrosion or influence other corrosion processes of metallic materials).
- Pipeline transports tariff quality dry gas (almost pure methane), with limited upsets introducing electrolyte or other contaminants, in which case internal corrosion risk has been managed.
- Pipeline is coated and cathodically protected (a technique to reduce the corrosion of a metal surface) and be in good condition. Coating must meet the requirements in 49 C.F.R. § 192.461 and be in good condition. Cathodic protection must be demonstrated generally effective.
- No history of stress corrosion cracking (the cracking induced from the combined influence of tensile stress and a corrosive environment).

⁴³Pipeline and Hazardous Materials Safety Administration, *Gas Transmission Pipeline Integrity Management Assessment: Proposed Reassessment Interval Extension Review*, (Apr. 15, 2008).

- Assumed corrosion growth rate is justified and supports the longer reassessment interval. Calculations of remaining time frame before pipeline failure are conservative and demonstrate safety for an extended interval.
- Few safety related conditions, leaks, incidents, or failures have resulted from corrosion, and the causes have been addressed.
- History of compliance with corrosion control, integrity management, operator qualification, and drug and alcohol testing regulations is good.
- Public awareness program meets the requirements in 49 C.F.R. § 192.616.
- No open corrective action orders or significant enforcement actions related to corrosion control program deficiencies affecting the involved pipeline segments.
- Pipeline must have been constructed after 1970 unless demonstration of good condition is provided.
- Environmental conditions in which the affected pipeline segment is located must not be unusually conducive to corrosion.

Appendix III: GAO Contact and Staff Acknowledgments

GAO Contact

Susan A. Fleming, (202) 512-2834, or flemings@gao.gov.

Staff Acknowledgments

In addition to the contact named above, Sara Vermillion (Assistant Director), Sarah Arnett, Russell Burnett, Leia Dickerson, Colin Fallon, David Hooper, Joshua Ormond, Daniel Paepke, Madhav Panwar, Anne Stevens, and Adam Yu made key contributions to this report.

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