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

The Honorable Frank Lautenberg
Chairman
Subcommittee on Surface Transportation and Merchant
Marine Infrastructure, Safety, and Security
Committee on Commerce, Science, and Transportation
United States Senate

Subject: Safety Effects of Less Prescriptive Requirements for Low-Stress Natural Gas Transmission Pipelines Are Uncertain

More than 2.6 million miles of pipelines form a nationwide network to transport the majority of natural gas consumed in the United States. This extensive gas pipeline network includes several different types of pipelines, including

- *transmission pipelines,* which transport product over long distances at high pressure from sources to communities;
- *distribution pipelines*, which operate at lower pressures to deliver natural gas to homes and businesses; and
- *low-stress transmission pipelines*, which typically connect transmission pipelines to distribution pipelines and may operate at pressures that are similar to the latter.

The Pipeline and Hazardous Materials Safety Administration (PHMSA), within the Department of Transportation (DOT), is responsible for establishing safety requirements for these pipelines and has traditionally included low-stress transmission pipelines in its regulations for all transmission pipelines. In 2004, PHMSA implemented a risk-based regulatory approach called “integrity management” for natural gas transmission pipelines, including low-stress

transmission pipelines.[1] In 2010, PHMSA extended integrity management to distribution pipelines, but modified the requirements to account for differences in transmission and distribution pipelines, such as differences in pipeline size and operating pressure.[2] Some stakeholders have suggested that the requirements for distribution pipelines should apply to low-stress transmission pipelines because of the similarity in operating pressures of these two types of pipelines. You asked that we consider the safety implications to the public of this proposal. Accordingly, this report focuses on how applying distribution integrity management requirements to low-stress gas transmission pipelines might affect the safety of these pipelines.

To perform our work, we reviewed and compared laws, regulations, and guidance from PHMSA. We also interviewed a broad range of stakeholders, including representatives of industry trade associations, pipeline safety advocacy groups, state pipeline agencies, and pipeline operators. In addition, we surveyed 52 officials from state pipeline safety agencies[3] in 50 states and the District of Columbia—achieving a 100 percent response rate—to collect information otherwise not available from PHMSA, including state officials' views on changing safety requirements for low-stress transmission pipelines. We also analyzed technical documents examining the point at which pipelines leak or rupture, reports on the integrity management program and related progress, and pipeline accident reports. Furthermore, we visited state pipeline safety officials and pipeline operators and associations in Colorado, Texas, and Pennsylvania, where we interviewed officials and representatives to obtain firsthand information on pipeline safety issues—including the potential effects of applying the new requirements for distribution pipelines to low-stress gas transmission pipelines—and examined pipeline infrastructure. We selected these sites as illustrative of differences in overall pipeline mileage, geography, and emerging pipeline issues.

We conducted this performance audit from February 2011 to January 2012 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.

Summary

Applying PHMSA's new distribution integrity management requirements to low-stress transmission pipelines would result in less prescriptive safety requirements for these pipelines. Overall, requirements for distribution pipelines are less prescriptive than requirements for transmission pipelines in part because the former operate at

[1]49 C.F.R. § 192, Subpart O.

[2]49 C.F.R. § 192, Subpart P.

[3]Two state pipeline safety officials from separate agencies in Arkansas that are responsible for overseeing pipeline safety in that state responded to our survey.

lower pressure and pose lower risks in general than the latter. For example, the integrity management regulations for transmission pipelines allow three types of in-depth physical inspections.[4] In contrast, distribution pipeline operators can customize their integrity management programs to the complexity of their systems, including using a broader range of methods for physical inspection. While PHMSA officials stated that "less prescriptive" does not necessarily mean less safe, they also stated that distribution integrity management requirements for distribution pipelines can be more difficult to enforce than integrity management requirements for transmission pipelines. Currently, PHMSA can grant special permits to modify requirements for individual pipelines, if merited,[5] but applying the new distribution integrity management requirements to low-stress transmission pipelines would affect all such pipelines.

If PHMSA's requirements for low-stress transmission pipelines changed, operators whose systems consist almost entirely of distribution pipelines and include only a short low-stress transmission pipeline segment could benefit because they would be subject to one set of integrity management requirements instead of two. This might allow them to apply more resources to other safety priorities. However, the effect of such a change on pipeline safety is unclear. While the consequences of a low-stress transmission pipeline failure are generally not severe because these pipelines are more likely to leak gradually rather than rupture, the point at which a gas pipeline fails by rupture is uncertain and depends on a number of factors in addition to pressure. For example, the size or type of defect and the materials used to construct the pipeline also influence whether a pipeline leaks or ruptures. In addition, the mileage and location of pipelines that would be affected by such a regulatory change are currently unknown, although PHMSA recently changed its reporting requirements to collect such information. The concern is that because distribution pipelines are located in highly populated areas, the low-stress transmission pipelines that are connected to them could also be located in highly populated areas. Overall, officials we contacted from state pipeline safety agencies and PHMSA supported the current integrity management requirements for low-stress transmission pipelines. Specifically, about 58 percent of the officials from state pipeline safety agencies we surveyed (30 of 52), responded that the current requirements would best apply to low-stress transmission pipelines—affirming the current regulatory environment. By comparison, 10 of 52 officials were in favor of changing the regulatory environment by applying distribution integrity management requirements to low-stress transmission pipelines, and 12 of 52 officials stated no opinion on the issue. In light of the uncertain safety effects of changing safety requirements for low-stress transmission pipelines and the opinion of state pipeline safety officials we surveyed, the current regulatory approach of applying more prescriptive transmission pipeline requirements—with an option for operators to apply for a special permit—appears reasonable.

[4]49 C.F.R. § 192.921.

[5]49 U.S.C. § 60118(c).

Background

A network of transmission and distribution pipelines covering more than 2.6 million miles transport the majority of natural gas consumed in the United States. Gas transmission pipelines typically move natural gas across state lines and over long distances, from sources to communities. These pipelines are typically 12 to 42 inches in diameter and can generally operate at pressures up to 72 percent of specified minimum yield strength (SMYS).[6] By contrast, local distribution pipelines generally operate within state boundaries to receive gas from transmission pipelines and distribute it to commercial and residential end users. Local distribution pipelines typically range from less than 0.5 to more than 24 inches in diameter and operate well below 20 percent of SMYS. Connecting the long-distance transmission pipelines to the local distribution pipelines are lower stress transmission pipelines that may transport natural gas for several miles at pressures between 20 and 30 percent of SMYS.

The major causes and consequences of accidental releases of gas from pipelines differ for transmission and distribution pipelines. Corrosion—either internal or external—is one of the leading causes of releases from gas transmission pipelines. Given the high pressure of the gas as it is transported through these pipelines, failures can lead to catastrophic ruptures, releasing high volumes of gas that can ignite and explode. For distribution pipelines, in contrast, damage from excavation and other outside forces is the major cause of accidental releases. Distribution pipeline failures are more likely to involve slow leaks with limited volume because the internal gas pressure is much lower than for transmission pipelines. Whatever the cause, however, leaks can lead to gas migrating to and accumulating in buildings, potentially igniting and causing a fire—which could result in injury or death to residents. Natural gas has traveled underground along migration pathways, such as sewer lines, finding an ignition source some distance from the location of the release. Therefore, monitoring pipeline integrity is important to prevent both leaks and ruptures.

PHMSA administers a national regulatory program intended to ensure the safe transportation of natural gas and hazardous liquid by pipeline. In general, PHMSA has full responsibility for inspecting interstate pipelines and enforcing regulations pertaining to them,[7] although some states are designated as “interstate agents” to assist PHMSA.[8] PHMSA also has arrangements with the 48 contiguous states, the

[6]Pipelines 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 SMYS. The SMYS 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 SMYS (49 CFR § 192.3). Some transmission pipelines operate under special permits that allow different maximum operating pressure that could exceed 72 percent of SMYS.

[7]49 U.S.C. § 60102.

[8]49 U.S.C. § 60106. The nine interstate agents for natural gas are Arizona, Connecticut, Iowa, Michigan, Minnesota, New York, Ohio, Washington, and West Virginia.

District of Columbia, and Puerto Rico to assist with overseeing intrastate pipelines. PHMSA and participating state pipeline safety offices oversee operators' compliance with two types of safety requirements: minimum safety standards and a supplemental, risk-based integrity management program. The minimum safety standards generally cover the design, construction, testing, inspection, operation, and maintenance of all pipelines, but generally do not account for differences in the kinds of threats and the degrees of risk that individual pipelines face. By contrast, PHMSA's integrity management program requires operators to periodically[9] assess their pipelines to identify threats and mitigate risks to pipeline segments in areas where the consequences of a pipeline failure would be most severe, such as populated areas.

The Pipeline Safety Improvement Act of 2002[10] required the Secretary of DOT to prescribe standards for gas transmission pipeline operators to implement integrity management plans, which led to the implementation of PHMSA's integrity management program for transmission pipelines in 2004.[11] Pursuant to the 2002 act, all gas transmission pipeline operators must periodically assess for and mitigate safety threats, such as corrosion. Integrity management requirements for transmission pipelines focus on portions of the pipeline located in highly populated or frequently used areas, like residential areas or parks, where significant consequences could result if an incident occurs. Such areas are referred to collectively as *high-consequence areas*.[12] Because the majority of transmission pipelines often traverse rural areas, including areas that are sparsely populated or where consequences would be low, the percentage of natural gas transmission pipeline mileage that is subject to integrity management requirements is small, about 7 percent. PHMSA also established provisions within transmission integrity management for low-stress transmission pipelines, in recognition that these pipelines are more likely to fail by leak rather than by rupture compared to higher pressure transmission pipelines and thus pose a reduced risk to the public. For example, an operator could conduct an electrical survey to address the threat of external corrosion, instead of utilizing the full external corrosion direct assessment process.

The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006[13] mandated that PHMSA also establish minimum standards for integrity management

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[9]For example, 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. 49 C.F.R. § 192.939.

[10]Pub. L. No. 107-355, § 14, 116 Stat. 2985, 3002 (Dec. 17, 2002).

[11]49 C.F.R. § part 192, subpart O.

[12]49 C.F.R. § 192.905.

[13]Pub. L. No. 109-468, § 9, 120 Stat. 3486 (2006).

programs for distribution pipelines; PHMSA published these standards in a final rule in December 2009.[14] These integrity management programs are similar to those required for gas transmission pipelines, but tailored to reflect the differences in distribution pipelines. For example, all distribution pipelines are considered to be in high-consequence areas because they are largely located in populated areas. As a result, distribution integrity management requirements apply to all distribution pipelines. The rule took effect February 2, 2010, and gas distribution operators were required to implement an integrity management program no later than August 2, 2011.[15]

Commenters on the distribution integrity management final rule in 2009 suggested that distribution operators that also operate low-stress gas transmission pipelines should be able to use distribution integrity management requirements for those transmission pipelines, rather than implement a separate integrity management plan.[16] Commenters suggested that this could be done by amending the distribution integrity management rule or by changing the definition of a transmission pipeline, but recognized that additional rulemaking might be needed as a result. In the final rule, PHMSA noted that stakeholder groups that studied the appropriateness of such a change concluded that additional technical work would be needed to support it. Specifically, they said a better understanding of the threshold between leakage and rupture was needed to determine if low-stress transmission pipelines should be regulated under a distribution integrity management program. PHMSA concluded that it might be appropriate to consider the change at a later date, and agreed with the need for additional technical work to inform any decision.

Less Prescriptive Requirements for Low-Stress Transmission Pipelines Could Benefit Some Operators, but Safety Effects Are Unknown

Changing Safety Requirements Would Result in Less Prescriptive Regulations for Low-Stress Gas Transmission Pipelines

Overall, integrity management—and most other—pipeline safety requirements are less prescriptive for distribution pipelines than for transmission pipelines. PHMSA's integrity management requirement for assessments of gas transmission pipelines illustrates the prescriptive nature of the safety requirements for transmission pipelines. This requirement directs operators to perform an integrity assessment (physical inspection) of their transmission pipelines using a specific method[17]—in-

[14]49 C.F.R. part 192, subpart P.

[15]49 C.F.R. § 192.1005.

[16]74 Fed. Reg. 63934 (December 4, 2009). Comment topic 8.

[17]49 C.F.R. § 192.921.In general, the maximum reassessment interval allowable is seven years (49 C.F.R. § 192.939).

line inspection,[18] hydrostatic pressure testing,[19] or direct assessment.[20] Both in-line inspection and hydrostatic testing involve tools or techniques applied inside the pipeline, while direct assessment tools and techniques are applied externally. These assessment methods allow operators to detect specific anomalies[21] in the pipeline, such as imperfections in the pipe wall or weld, that could lead to failure. (See fig. 1 for an example of the equipment used for hydrostatic testing and fig. 2 for an example of the equipment involved in in-line inspections.)

Figure 1: Hydrostatic Testing Equipment Used to Test Pipeline Integrity

Sources: Texas Oil and Gas Association.

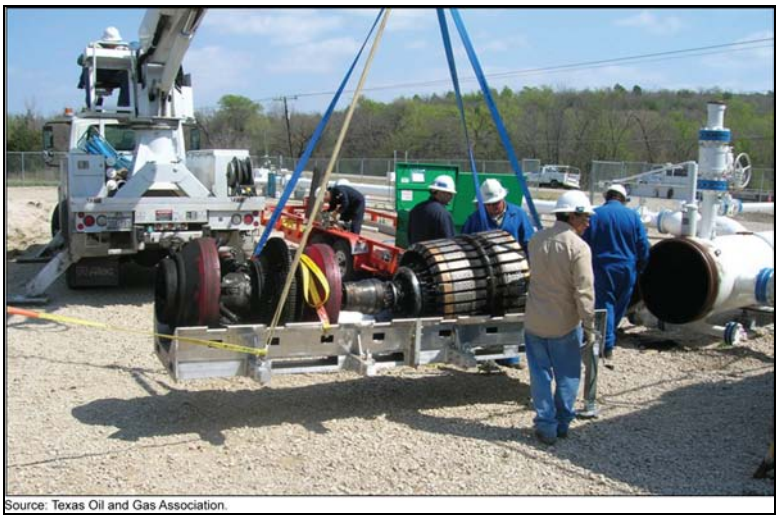
[18]In-line inspection involves running a specialized tool—often known as a smart pig—through the pipeline to detect and record anomalies, such as metal loss and damage. In-line inspection allows operators to determine the nature of any problems without either shutting down the pipeline for extended periods or damaging the pipeline. In-line inspection devices can be run only from facilities established for launching and retrieving them.

[19]Hydrostatic pressure testing entails sealing off a portion of the pipeline, removing the gas product, filling the pipeline segment 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 pipeline is excavated to determine the cause of the failure. Operators must shut down pipelines to perform hydrostatic testing.

[20]Direct assessment is a nonintrusive, aboveground instrument inspection that uses two or more types of diagnostic tools, such as a closed interval survey—to assess the coating of covered pipelines for corrosion damage—at predetermined intervals along the pipeline. Once the data are analyzed, the operator excavates and inspects segments of the pipeline suspected to have safety threats.

[21]All pipelines have anomalies, most of which are nonproblematic, in that they will not grow or lead to pipeline failure over time. Integrity management inspections are designed specifically to identify and control anomalies that can possibly lead to failure.

Figure 2: Example of In-Line Inspection Equipment to Detect and Record Pipeline Anomalies



Source: Texas Oil and Gas Association.

In developing integrity management requirements for distribution pipelines, PHMSA did not prescribe the same types of assessments as it did for its transmission pipelines, because the assessments would often not be practicable for distribution pipelines. For example:

- Distribution pipelines are typically too narrow in diameter to accommodate in-line inspection tools.
- Approximately half of the distribution pipeline system is nonmetallic, meaning that internal inspection tools cannot be used.[22]
- Hydrostatic testing and direct assessment are time consuming and can be risky and inconvenient for the public. During a hydrotest, pipelines must be shut down and gas deliveries must be stopped or curtailed for some time.
- Hydrostatic testing and direct assessment can interfere with normal activities in the vicinity of the testing. In particular, direct assessment involves excavation and disturbs property and infrastructure, potentially including roads and other utilities, with which distribution pipelines may be integrated.

PHMSA's approach for distribution pipelines requires all operators to implement an integrity management program that sets high-level performance objectives with implementation guidelines. For example, PHMSA requires pipeline operators to develop an integrity management program incorporating certain elements—such as identifying risks, evaluating and ranking risks, and identifying measures to address

[22]In-line inspection tools use magnets to detect disturbances in the magnetic field that are caused by defects in the pipe. As a result, this method would be ineffective with plastic pipe.

risks. [23] Operators have the flexibility, however, to create a plan at their discretion as long as they demonstrate how it satisfies integrity management requirements, which could include a broad range of preventative or mitigative methods. For example, a distribution operator may conduct a guided wave pipeline assessment, which uses ultrasonic waves to scan and inspect the pipe. While PHMSA officials stated that "less prescriptive" does not necessarily mean less safe, they also stated that integrity management requirements for distribution pipelines can be more difficult to enforce than integrity management requirements for transmission pipelines. This is because transmission pipelines must meet a specific set of fixed requirements as opposed to the flexible program allowed under distribution integrity management.

Other regulatory requirements—not just integrity management regulations—are also generally less prescriptive for distribution pipelines than for transmission pipelines, because distribution pipelines operate at lower pressures and pose lower risks. Specifically, regulations for valve spacing, construction, patrolling, line markers, recordkeeping, and leak repairs are all less prescriptive for distribution pipelines. For example, operators must patrol distribution pipelines to observe surface conditions at least twice a calendar year in areas or on structures where physical movement or external loading could cause failure or leakage, but for transmission pipelines in the most densely populated (high-consequence) areas, operators must patrol at least four times per year. As a result, if low-stress transmission pipelines adopted distribution pipeline requirements, then low-stress transmission pipelines located in highly populated (high-consequence) areas would be subject to less frequent leak surveys and patrolling than other transmission pipelines.

As an alternative to changing the safety requirements for all low-stress transmission pipelines, PHMSA can currently issue special permits exempting operators from compliance with one or more regulations.[24] The special permit process would allow PHMSA to evaluate the safety implications of the exemptions on a case-by-case basis, as opposed to applying less prescriptive requirements across the board for these types of pipelines. As of January 2012, PHMSA officials told us they have not received any requests for special permits to apply distribution integrity management requirements to low-stress transmission pipelines.

[23]Distribution integrity management plans include seven key elements: (1) have an understanding of the system, including the conditions and factors important to assessing risks; (2) identify threats applicable to the system, including potential future threats; (3) assess risks and characterize the relative significance of applicable threats to the system; (4) identify and put in place appropriate risk-control practices to prevent and mitigate risks from applicable threats consistent with the significance of these threats; (5) develop and monitor performance measures to evaluate effectiveness of programs, periodically evaluate program effectiveness, and adjust programs, as needed, to assure effectiveness; (6) must reevaluate threats and risks, determine the appropriate period for conducting complete program evaluations at least every 5 years and (7) periodically report a select set of performance measures to jurisdictional authorities. 49 C.F.R. Part 192, Subpart P.

[24]49 U.S.C. § 60118(c).

Changing Requirements Could Benefit Some Operators, but Overall Effects on Safety Are Unknown

Changing the safety requirements for low-stress gas transmission pipelines could simplify compliance and create efficiencies for some pipeline operators, potentially allowing them to apply resources to other safety priorities. In 2006, we reported that according to operators, integrity management can be costly, when, for example, additional staff or contractors must be hired to implement integrity management requirements.[25] Under the current regulations, some pipeline companies operating both distribution and low-stress transmission pipelines must address requirements for both distribution and transmission integrity management programs. While it is possible to have one integrity management plan that addresses both distribution and transmission integrity management requirements, some of these companies operate only a small segment of transmission pipeline that connects to an entire distribution pipeline network. For such companies, changing the safety requirements for low-stress transmission pipelines could create efficiencies because they would be subject to just one set of integrity management requirements. Furthermore, operators devote resources to comply with pipeline safety regulations, and these safety resources could be made available for other safety purposes.

While changing the requirements for low-stress pipelines would benefit some operators, the impact on pipeline safety is unclear. For example, although low-stress gas transmission pipelines typically operate at pressures at which a pipeline failure will result in a leak, recent research has indicated that there is no definitive threshold at which a pipeline will leak as opposed to rupture, since pipeline integrity depends on a number of characteristics in addition to operating pressure. Though in general the threshold is in the range of 20 to 30 percent of SMYS—which is the typical operating pressure for low-stress transmission pipelines—the point at which a pipeline will rupture instead of leak varies depending on factors such as toughness, wall thickness, and the diameter of the pipe segment. For example, a 2011 study[26] determined that the boundary could range from slightly below 20 percent of SMYS for pipelines with rarely used pipe materials to well over 30 percent of SMYS for many other pipelines with more robust materials. Furthermore, a 2001 study[27] determined that pipelines operating at less than 30 percent of SMYS are more likely to leak than to rupture, but noted that pipelines operating at lower pressure have also ruptured, because of a combination of factors such as the length of the defect and toughness of the pipe. According to one of the researchers of the study,

[25]GAO, *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).

[26]Gas Technology Institute, GTI, *Leak-Rupture Boundary Determination Project*, (Des Plaines, IL: December 2011). GTI completed a study funded by Operations Technology Development using incident and laboratory testing data with advanced modeling techniques to calculate the boundary between failure by leak and failure by rupture as a function of the pipe's SMYS.

[27]Gas Research Institute, *Leak versus Rupture Considerations for Steel Low-Stress Pipelines,* GRI-00/0232, (Des Plaines, IL: January 2001). The report evaluated leak versus rupture as a function of wall stress, with a focus on natural gas pipelines operating through high-consequence areas.

additional factors—such as damage incurred during installation and subsequent pressure increases around the damage—could increase the likelihood of an incident, even for lower pressure pipelines. In addition, some high-profile incidents have occurred on transmission pipelines operating at pressures slightly higher than 30 percent of SMYS.[28] For example, on September 9, 2010, a 30-inch-diameter underground natural gas transmission pipeline operating at 35 percent of SMYS in a residential area of San Bruno, California, suddenly ruptured. The resulting explosion and fire killed 8 people and destroyed 38 homes.

Another reason why the effects of changing the safety requirements for low-stress transmission are unclear is that the mileage and location of pipelines that would be affected by such a change are currently unknown. The concern is that low-stress transmission pipelines subject to a change in safety requirements could be located in high-consequence areas. PHMSA did not collect this information in the past, although it recently revised its reporting requirements to do so. PHMSA's transmission pipeline annual report form—revised in November 2010 for 2011 reporting[29]—now requests information on the number of miles of pipeline and location by operating percentage of SMYS for each operator. Furthermore, of the 52 officials from state pipeline safety agencies we surveyed, 31 responded that they do not track the location of the low-stress gas transmission pipelines in their state.[30] However, by definition, low-stress transmission pipelines could be located in high-consequence areas because these pipelines connect to distribution pipeline networks. Therefore, a change in safety requirements could mean that low-stress gas transmission pipelines in high-consequence areas would now be subject to less prescriptive integrity management requirements.

Overall, officials we contacted from state pipeline safety agencies and PHMSA supported the current integrity management requirements for low-stress transmission pipelines. For example, of the 52 officials from state pipeline safety agencies we surveyed, 30 responded that transmission pipeline integrity management requirements would better apply to low-stress transmission pipelines—affirming the current regulatory environment. By contrast, 10 of 52 officials from state pipeline safety agencies responded that distribution integrity management requirements would be better for these types of pipelines.[31] Furthermore, according to some PHMSA officials, lower stress transmission pipelines should be subject to

[28]According to PHMSA, its database of significant incidents for gas transmission pipelines from 2010 to January 2012 identified 27 incidents that occurred on pipelines operating at pressures greater than or equal to 30 percent of SMYS to less than 40 percent of SMYS at the time of the incident. Of the 27 incidents, 3 were identified as the "rupture" release type occurring at percentages of SMYS close to 30 percent.

[29]49 C.F.R. §§ 191, 192, 193, and 195.

[30]Of the 52 officials from state pipeline safety agencies we surveyed, 18 responded that they do track the location of low-stress gas transmission pipelines, and another 3 officials responded that they did not know.

[31]Of the 52 officials from state pipeline safety agencies surveyed, 12 responded that they had no opinion on the matter.

more prescriptive requirements than would be applicable under the distribution integrity management program because low-pressure leaks can still cause significant damage.

Concluding Observations

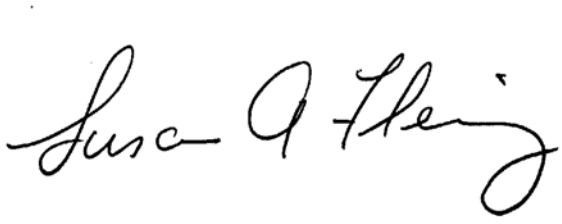
Even though some pipeline operators might benefit from changing the regulations for low-stress transmission pipelines, the uncertain safety effects raise concerns about this change. In the current regulations, pipelines operating at below 20 percent of SMYS are subject to less prescriptive requirements, but a change could mean that pipelines operating at up to 30 percent of SMYS would also be subject to less prescriptive requirements. Given the lack of a definitive threshold at which pipelines that operate in this pressure range will rupture, not knowing the mileage and location of pipelines that would be affected by a change in requirements and not knowing the potential proximity of these pipelines to high-consequence areas makes such a change questionable. Furthermore, the majority of state pipeline safety officials responding to our survey support maintaining the current regulatory environment, which includes an option for operators to apply for a special permit if complying with requirements for two separate integrity management programs would be burdensome.

Agency Comments

We provided a draft of this correspondence to DOT officials for their review and comment. The officials provided technical corrections which we have incorporated throughout.

We are sending copies of this report to the Secretary of Transportation. The report is also available at no charge on the GAO Web site at http://www.gao.gov.

If you or your staff have any questions concerning this correspondence, 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 correspondence. Major contributors to this correspondence were Sara Vermillion, Assistant Director; Adam Yu, Analyst-in-Charge; Aisha Cabrer; Matt Cail; Elizabeth Eisenstadt; Colin Fallon; David Hooper; and Rebecca Shea.



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