United States Government Accountability Office

Report to Congressional Committees

August 2017

PIPELINE SAFETY

Additional Actions Could Improve Federal Use of Data on Pipeline Materials and Corrosion

GAO-17-639

GAO Highlights

Highlights of GAO-17-639, a report to congressional committees

August 2017

PIPELINE SAFETY

Additional Actions Could Improve Federal Use of Data on Pipeline Materials and Corrosion

Why GAO Did This Study

The U.S. energy pipeline network is composed of over 2.7-million miles of pipelines transporting gas and hazardous liquids. While pipelines are a relatively safe mode of transportation, incidents caused by material failures and corrosion may result in fatalities and environmental damage. PHMSA, an agency within the Department of Transportation, inspects pipeline operators and oversees safety regulations.

2016 pipeline safety legislation included a provision for GAO to examine a variety of topics related to pipeline materials and corrosion. This report addresses: (1) the materials and corrosion-prevention technologies used in the pipeline network and their benefits and limitations and (2) how PHMSA uses data on pipelines and corrosion to inform inspection priorities, among other topics. GAO analyzed PHMSA's 2010–2016 data; reviewed PHMSA regulations; and interviewed PHMSA officials and representatives of nine states selected based on pipeline inspection roles, eight pipeline operators—providing a range of sizes, geographic locations, and other factors—and eight stakeholders selected for expertise on pipeline and corrosion issues.

What GAO Recommends

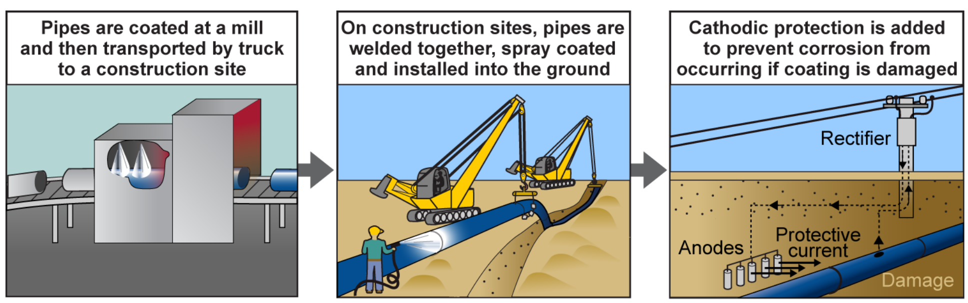
GAO recommends that PHMSA document the design of its Risk Ranking Index Model and implement a process that uses data to periodically assess the model's effectiveness. The Department of Transportation agreed with our recommendation and provided technical comments, which we incorporated as appropriate.

View GAO-17-639. For more information, contact Susan Fleming at (202) 512-2834 or FlemingS@gao.gov.

What GAO Found

The U.S. gas and hazardous liquid pipeline network is constructed primarily of steel and plastic pipes, both of which offer benefits and limitations that present trade-offs to pipeline operators, as do corrosion prevention technology options. According to data from the Pipeline and Hazardous Materials Safety Administration (PHMSA), over 98 percent of federally regulated pipelines that gather natural gas and other gases and hazardous liquid products, such as oil, and transmit those products across long distances are made of steel. An increasing majority of pipelines that distribute natural gas to homes and businesses are made of plastics. Steel pipelines are manufactured in various grades to accommodate higher operating pressures, but require corrosion protection and cost more than plastics, according to operators and experts. In contrast, plastics and emerging composite materials generally are corrosion-resistant, but lack the strength to accommodate high-operating pressures. Operators use a range of technologies to protect steel pipes from corrosion, including applying coatings and cathodic protection, which applies an electrical current to the pipe. (See fig.) While such technologies are generally considered effective, operators and experts stated that coatings degrade over time and that cathodic protection requires ongoing maintenance and costs to deliver the current over long pipeline distances, among other considerations.

Application and Installation of Pipeline Coating and Cathodic Protection



Source: GAO analysis of Pipeline and Hazardous Materials Safety Administration information. | GAO-17-639

PHMSA uses materials and corrosion data collected from operators in its Risk Ranking Index Model to determine the frequency of PHMSA's inspections of operators based on threats, such as ineffective coatings, to pipeline integrity. PHMSA officials said they used professional judgment to develop their model, but did not document key decisions for: (1) the threat factors selected, (2) their associated weights, or (3) the thresholds for high, medium, and low risk tiers for pipeline segments inspected by PHMSA. Moreover, PHMSA has not used data to assess its model's overall effectiveness, as would be consistent with federal management principles. PHMSA officials said they have not established an evaluation process because they consider the model to be effective in prioritizing inspections. Although PHMSA officials said they analyzed the model when they developed it in 2012, they have not done so since that time and did not document the results of this initial analysis. Without documentation and a data-driven evaluation process, PHMSA cannot demonstrate the effectiveness of the model it uses to allocate PHMSA's limited inspection resources.

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Abbreviations

ASME	American Society of Mechanical Engineers
NACE	National Association of Corrosion Engineers
NTSB	National Transportation Safety Board
OMB	Office of Management and Budget
PHMSA	Pipeline and Hazardous Materials Safety Administration
psi	pounds per square inch
RRIM	Risk Ranking Index Model

U.S. GOVERNMENT ACCOUNTABILITY OFFICE
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August 3, 2017

The Honorable John Thune
Chairman
The Honorable Bill Nelson
Ranking Member
Committee on Commerce, Science and Transportation
United States Senate

The Honorable Bill Shuster
Chairman
The Honorable Peter DeFazio
Ranking Member
Committee on Transportation and Infrastructure
House of Representatives

The Honorable Greg Walden
Chairman
The Honorable Frank Pallone
Ranking Member
Committee on Energy and Commerce
House of Representatives

The U.S. energy pipeline network is composed of over 2.7-million miles of pipeline transporting gas, oil, and other hazardous liquids across the country.[1] This network is owned, operated, and maintained by about 3,000 pipeline operators; the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) is responsible for overseeing the network's safety. Pipelines are relatively safe when compared with other transportation modes, such as rail and truck, though when pipeline incidents do occur they can result in fatalities and environmental damage.[2] While pipeline incidents may be caused by a variety of factors, from 2010 through 2015, pipeline material and weld

[1] In this report, we use the term gas to include natural gas, flammable gas, or gas that is toxic or corrosive.

[2] In its regulations, PHMSA refers to the release of gas from a pipeline as an incident and a spill from a hazardous liquid pipeline as an accident. (49 C.F.R. §§ 191.3 and 195.50). For simplicity, this report will refer to both as incidents.

failures and corrosion[3] were the reported cause of about one-third of significant pipeline incidents across the pipeline network, according to data collected by PHMSA.[4] For example, according to the National Transportation Safety Board (NTSB), external corrosion and the failure to detect that corrosion were the probable causes of a 2012 natural gas transmission pipeline rupture in Sissonville, West Virginia. The rupture destroyed and damaged several houses, and released and burned nearly 76-million cubic feet of natural gas.[5] This incident and others have raised questions about the materials used to construct pipelines and associated corrosion prevention technologies, the training and experience of the personnel that prevent and manage corrosion, and how PHMSA uses data on corrosion and materials to oversee pipeline safety.

The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 included a provision for us to report on a variety of topics related to pipeline materials, training, and corrosion prevention technologies for gas and hazardous liquid pipelines.[6] This report discusses:

1. the pipeline materials and corrosion prevention technologies that are used in the gas and hazardous liquid pipeline network and their respective benefits and limitations;
2. how selected pipeline operators train personnel to manage corrosion and the challenges that exist in ensuring personnel are qualified; and

[3]Corrosion is defined by PHMSA as the deterioration of a material (usually a metal) that results from a reaction with its environment.

[4]PHMSA defines significant incidents in internal guidance as those including any of the following conditions: fatality or injury requiring in-patient hospitalization; $50,000 or more in total costs (in 1984 dollars); highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more; or liquid releases resulting in an unintentional fire or explosion. Gas distribution incidents caused by a nearby fire or explosion that affected the pipeline system are not considered significant incidents under this definition.

[5]NTSB*, Pipeline Accident Report: Columbia Gas Transmission Corporation Pipeline Rupture, Sissonville, West Virginia, December 11, 2012*, NTSB/PAR-14/01 PB2014-103977 (Washington, D.C.: Feb. 19, 2014). The NTSB is required by statute to investigate all civil aviation accidents and selected accidents in other modes—highway, marine, railroad, pipeline, and hazardous materials. 49 U.S.C. § 1131(a)(1). NTSB also has the authority to investigate any other accident related to the transportation of individuals or property when its board decides the accident is catastrophic or involves problems of a recurring character, or the investigation would help carry out NTSB authorities for accident investigation. 49 U.S.C. § 1131(a)(1)(F).

[6]Pub. L. No. 114-183, § 21, 130 Stat. 514, 528.

3. how PHMSA uses data on pipelines and corrosion prevention to inform its inspection priorities.

This report also includes information on the use of pipeline materials and corrosion prevention technologies outside the United States as well as potential future improvements in materials and corrosion prevention technologies. (See app. I.)

For each of these objectives, we reviewed pertinent PHMSA regulations and documents and interviewed PHMSA headquarters officials. To determine what pipeline materials and corrosion prevention technologies are used in the gas and hazardous liquid networks, we analyzed the most recent full-year data (calendar years 2010–2015) on pipeline characteristics and corrosion prevention technologies reported to PHMSA by pipeline operators. To assess the benefits and limitations of these materials and technologies, we reviewed Department of Transportation reports and academic literature, and interviewed a nongeneralizable sample of eight pipeline operators and eight stakeholders with expertise on pipeline materials and corrosion (expert stakeholders).[7] These pipeline operators represent a range of pipeline functions, types of materials transported, the network size (miles of pipeline), geography, and recommendations from other stakeholders. We selected expert stakeholders based on their knowledge of pipeline materials and corrosion as determined by their employment or experience, and recommendations of other expert stakeholders. The views provided by pipeline operators and expert stakeholders cannot be generalized to all pipeline operators and experts, but do provide perspectives on the benefits, limitations, costs and other aspects of the pipeline materials and corrosion prevention technologies discussed in these interviews.[8]

To analyze how selected pipeline operators train personnel to manage corrosion, we reviewed PHMSA regulations and proposed changes to

[7]For the purposes of this report, we refer to stakeholders with expertise on pipeline materials and corrosion as expert stakeholders.

[8]While we collected information on benefits, limitations, and factors affecting cost from these interviews, we did not review cost-benefit analyses or conduct a formal cost-benefit analysis due to a lack of available data for pipeline materials and corrosion technologies across the network. In addition, while we asked operators and expert stakeholders about the cost of materials and corrosion prevention technologies during our interviews, many stated that they could not provide estimates for specific materials and technologies, in part because estimates depend on a variety of factors. As result, we reported on factors affecting the cost of these materials and technologies, rather than specific cost estimates.

those regulations requiring that pipeline operator personnel are qualified for operational and maintenance tasks, including corrosion prevention activities. We reviewed pipeline operator training plans and other documentation. We interviewed 17 stakeholders, including staff from the eight selected pipeline operators, as well as staff from three unions, three training providers and three industry associations. These interviews provided a range of views on approaches, common practices, and challenges associated with corrosion training and are not generalizable across all industry stakeholders.

To determine how PHMSA uses data on materials and corrosion prevention to inform its inspection priorities, we analyzed and assessed the reliability of the most recent PHMSA inspection and enforcement data (calendar years 2014–2016) that contained information related to pipelines and corrosion prevention. We evaluated PHMSA's use of these data in its risk-ranking index model that PHMSA uses to rank the relative risk of pipelines and prioritize its annual inspections of pipeline operators. We compared this approach to criteria identified in *GAO's Standards for Internal Controls in the Federal Government's*[9] criteria for risk analysis developed by the Office of Management and Budget (OMB) and PHMSA's strategic objectives.[10] To understand how inspection data are collected and used to inform PHSMA's oversight, we interviewed staff from each of PHMSA's five regional offices, which are responsible for conducting inspections of pipeline operator operations. We also conducted a group discussion with officials from all nine states that have been designated as "interstate agents" to assist PHMSA in inspecting interstate pipelines.[11] To assess the reliability of the data used in our review, we examined PHMSA reports, analyzed the data to identify any outlier values, and interviewed PHMSA officials about how the data were collected, stored, and validated, among other things. We determined that

[9]GAO, *Standards for Internal Control in the Federal Government*, GAO-14-704G (Washington, D.C.: Sept. 10, 2014).

[10]OMB, *Updated Principles for Risk Analysis*, OMB-M-07-24 (Washington, D.C.: Sept. 19, 2007), and OMB, *Management's Responsibility for Enterprise Risk Management and Internal Control*, Circular No. A-123 (Washington, D.C.: Jul. 15, 2016).

[11]"Interstate agents" are authorized by PHMSA to assist with the inspection of interstate pipelines. 49 U.S.C. § 60106. Of the nine states designated as interstate agents, four states (Connecticut, Michigan, Iowa, and Ohio) are designated solely as interstate agents for natural gas; one state is designated solely as an interstate agent for hazardous liquids (Virginia), and four states (Arizona, Minnesota, New York and Washington) are designated for both.

the data were sufficiently reliable for the purposes of our reporting objectives. Additional information on our objectives, scope, and methodology is included in appendix II.

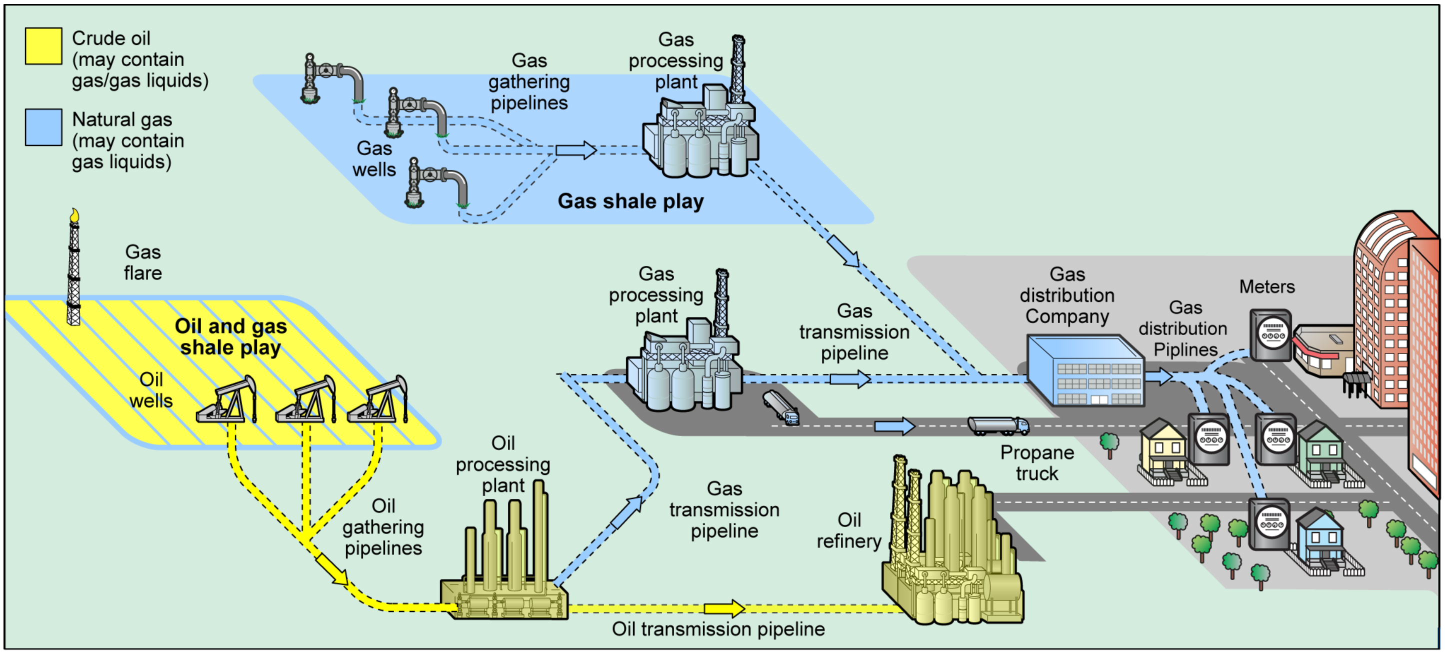
We conducted this performance audit from July 2016 to August 2017 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based 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

More than 2.7-million miles of pipeline transport roughly two-thirds of our nation's domestic energy supply. These pipelines carry gas and hazardous liquids from producing wells, to processing plants, and eventually to end users, such as businesses and homes. (See fig. 1.) Within this nationwide system, there are three main types of pipelines—gathering, transmission, and distribution. Based on annual reports submitted to PHMSA by pipeline operators at the end of 2015, there were about 18,000 miles of gas gathering pipelines, 301,000 miles of gas transmission pipelines, and 2.2 million miles of gas distribution pipelines regulated by PHMSA. In addition, in 2015 there were about 4,000 miles of liquid gathering pipelines and 205,000 miles of hazardous liquid transmission pipelines regulated by PHMSA.[12]

[12]Certain types of gathering pipelines are not regulated by PHMSA. 49 U.S.C. §60101(b). For example, PHMSA only regulates gas gathering pipelines in non-rural areas, resulting in regulation and inspection of approximately 5 percent of gas gathering pipelines and approximately 10 percent of hazardous liquid pipelines. Our prior work has noted that PHMSA lacks data on unregulated gathering pipelines, and recommended that the agency collect data on these pipelines, comparable to what is currently collected for regulated gathering pipelines, in order to enhance pipeline safety. See GAO, *Pipeline Safety: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety*, GAO-12-388 (Washington, D.C.: Mar. 22, 2012). This recommendation remains open. PHMSA has proposed regulations to collect additional data on gathering pipelines for gas and hazardous liquids but these rules have not yet been finalized by PHMSA. See 80 Fed. Reg. 61610 (Oct. 13, 2015) and 81 Fed. Reg. 20722 (Apr. 8, 2016).

Figure 1: Gas and Hazardous Liquid Pipeline Network



Source: GAO. | GAO-17-639

Note: Oil products are also transmitted from the refinery through transmission pipelines to storage tanks and other facilities not depicted in this figure.

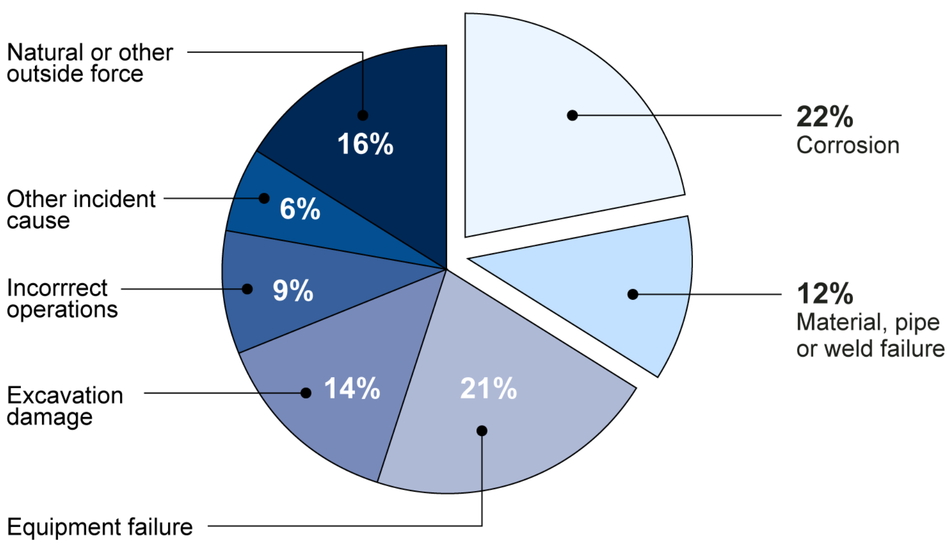
- *Gathering pipelines*: Gas gathering pipelines collect natural gas and other gases from production areas, while hazardous liquid gathering pipelines collect oil and other petroleum products from oil well heads. Gathering pipelines operate at pressures ranging from about 5 to 800 pounds per square inch (psi). These pipelines then typically transport the products to processing facilities, which in turn refine the products and send them to transmission pipelines.
- *Transmission pipelines*: Transmission pipelines carry gas or hazardous liquids, sometimes over hundreds of miles, to communities and large-volume users (e.g., factories).[13] Transmission pipelines tend to have the largest pressures of the three types of pipelines, generally operating at pressures ranging from 400 to 1,440 psi.
- *Gas distribution pipelines*: Gas distribution pipelines transport natural and other gas products to residential, commercial, and industrial

[13]For the purposes of this report, we use the term transmission pipeline to refer to both gas and hazardous liquid pipelines carrying product over long distances to users.

customers. These pipelines tend to operate at lower pressures—0.25 to 100 psi.

As noted earlier, pipeline material and weld failures and corrosion together are among the leading causes of significant incidents from 2010 through 2015, as reported to PHMSA by pipeline operators. (See fig. 2.) Material failures can occur due to impurities in the steel manufacturing process, defects in the manufacturing process to convert steel into pipelines, or from failures in the welding or joining of pipeline segments together, among other causes. Corrosion can occur on the exterior or interior of a metallic pipeline, during which electrons from the metal undergo electrochemical reactions often involving water or oxygen, resulting in the degradation of the pipeline. External corrosion may result when the metal surface of the pipe is exposed to groundwater or soil environments that increase electrical conductivity of a pipeline and accelerate the corrosion process. External corrosion is also a factor in stress corrosion cracking, where stress on the pipeline from high or fluctuating operating pressures and corrosive environmental conditions cause cracks to form in pipeline material. Internal corrosion occurs inside the pipeline, and may be caused by the presence of water, corrosive materials, or bacteria.

Figure 2: Operator-Reported Causes of Significant Pipeline Incidents, 2010–2015 (1,737 total)



Source: GAO analysis of Pipeline and Hazardous Materials Safety Administration (PHMSA) information. | GAO-17-639

Note: PHMSA defines significant pipeline incidents in its internal guidance as those including any of the following conditions: fatality or injury requiring in-patient hospitalization; $50,000 or more in total costs (in 1984 dollars); highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more; or liquid releases resulting in an unintentional fire or explosion. Gas distribution incidents caused by a nearby fire or explosion that affected the pipeline system are not considered significant incidents under this definition.

PHMSA has established regulations that identify requirements for pipeline materials and corrosion prevention technologies in the gas and hazardous liquid pipeline network.[14] PHMSA's regulations identify design standards for pipelines and regulate what materials can be used under different operating conditions and pressures.[15] For corrosion prevention, external coatings and a technology known as cathodic protection are required for metallic pipes installed beginning in 1971.[16] External coatings are a protective layer of plastic material or other chemical compounds applied and bonded across the metallic surface of a pipe. Coatings are applied prior to or during installation, and coat both the pipe and the welds that join pipeline segments together. However, external coatings can be damaged by construction or degrade over time. Therefore, after the external coatings are applied, cathodic protection is added. Cathodic protection involves applying an electrical current onto the pipeline to control external corrosion.[17] External coatings and cathodic protection thus work together to protect the pipeline by disrupting the chemical process that leads to corrosion. (See fig. 3.)

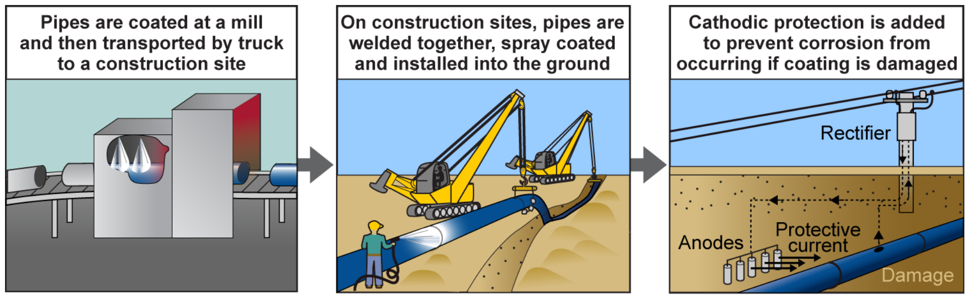
[14] 49 C.F.R. § 192.451–491 (gas); 49 C.F.R. § 195.551–591 (hazardous liquids).

[15] 49 C.F.R. § 192.101–125 (gas); 49 C.F.R. § 195.100–134 (hazardous liquids).

[16] Operators are required to cathodically protect metallic pipelines installed before 1971 in which active corrosion is found in (1) bare or ineffectively coated transmission lines; (2) bare or coated pipes at compressor, regulator, and measuring stations, or (3) a bare or coated distribution line. (49 C.F.R. § 192.457 (b)).

[17] According to PHMSA, cathodic protection systems help prevent corrosion from occurring on the exterior of pipes by substituting a new source of electrons, commonly referred to as a "sacrificial anode" or "impressed current anode." Both systems operate by imparting a direct current onto the buried pipeline, using devices called rectifiers. As long as the current is sufficient, the corrosion is prevented, or at least mitigated and held in check.

Figure 3: Example of External Coating and Cathodic Protection Installation and Application



Source: GAO analysis of Pipeline and Hazardous Materials Safety Administration information. | GAO-17-639

Under PHMSA's pipeline safety program, pipeline operators take primary responsibility for the integrity of their pipelines, and PHMSA conducts inspections to ensure operator compliance with federal safety regulations. For example, the Pipeline Safety Improvement Act of 2002 required PHMSA to implement a risk-based approach to gas and hazardous liquid 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 environmentally sensitive areas.[18] PHMSA and state pipeline safety offices conduct inspections to oversee operators' compliance with this and other federal requirements.

PHMSA has also established regulations requiring operators to ensure that personnel are qualified to perform certain tasks, including corrosion control activities such as monitoring cathodic protection.[19] In its operator qualification regulations, PHMSA has stated its objective is to reduce the risk of accidents on pipelines attributable to human error.[20] These regulations require that operators develop a written qualification plan that identifies a list of covered tasks for personnel as well as an approach to

[18]Pub. L. No. 107-355, § 14(a), 116. Stat. 2985, 3002 (2002) (codified as amended at 49 U.S.C. § 60109(c)(3)(A)-(B)). PHMSA defines "high-consequence areas" differently for gas and hazardous liquid. For gas, high-consequence areas typically include highly populated or frequented areas, such as parks (49 C.F.R. § 192.903). For hazardous liquid, high-consequence areas include highly populated areas, other populated areas, navigable waterways, and areas unusually sensitive to environmental damage.

[19]49 C.F.R. § 192.801-809 (gas); 49 C.F.R. § 195.501–509 (hazardous liquids).

[20]64 Fed. Reg. 46853 (Aug. 27, 1999).

evaluate whether individuals are qualified to perform those tasks.[21] (See table 1.) Operator qualification plans may include provisions to provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures safe operation.[22] The regulations do not prescribe how operators must evaluate personnel to ensure they are qualified, though they state the evaluation may take the form of a written or oral exam, on-the-job performance assessment, or a simulation, among other methods. [23]

Table 1: Examples of Covered Tasks Related To Corrosion

Example	Definition
Measure external corrosion	Investigate the extent of external corrosion and record data.
Coating application and repair: Sprayed	Prepare the surface (e.g., exterior of a pipe) and apply or repair coating using a sprayer.
Troubleshoot active cathodic protection system	Determine the reason for the cathodic protection system's failure and identify the required corrective action.

Source: American Society of Mechanical Engineers (ASME), *Pipeline Personnel Qualification, ASME Code for Pressure Piping*, B-31, ASME B31Q-2016. | GAO-17-639

Note: A covered task is an activity, identified by the operator, that: (1) is performed on a pipeline facility; (2) is an operations or maintenance task; (3) is performed as a requirement of this regulation; and (4) affects the operation or integrity of the pipeline. 49 C.F.R. § 192.801 (gas) and 49 C.F.R. § 195.501 (hazardous liquids).

PHMSA and state pipeline safety offices work together to oversee and inspect federally regulated gas and hazardous liquid pipelines. In general, PHMSA has primary authority to regulate and enforce interstate pipeline safety, including the design, construction, operation and maintenance of pipelines certified by the Federal Energy Regulatory Commission or crossing state lines.[24] In the nine states designated as interstate agents, state pipeline inspection staff supplements PHMSA inspections, but PHMSA maintains enforcement authority over these pipelines. Regarding

[21]A covered task is an activity, identified by the operator, that: (1) is performed on a pipeline facility; (2) is an operations or maintenance task; (3) is performed as a requirement of this regulation; and (4) affects the operation or integrity of the pipeline. 49 C.F.R. § 192.801 (gas) and 49 C.F.R. § 195.501 (hazardous liquids).

[22]49 C.F.R. § 192.805(h) and 49 C.F.R. § 195.505(h).

[23]49 C.F.R. § 192.803, Subpart N and 49 C.F.R. § 195.503.

[24]The Federal Energy Regulatory Commission approves the construction of interstate pipelines by issuing a certificate of public convenience and necessity, which includes conditions that the pipeline company receive all required federal authorizations before beginning construction, if it has not already done so. 15 U.S.C. § 717.

intrastate pipelines, state pipeline safety offices may assume inspection and enforcement responsibility for intrastate pipelines in their states after annually certifying to PHMSA that they are complying with applicable federal standards for their oversight.[25] PHMSA currently has certifications with the 48 contiguous states, the District of Columbia, and Puerto Rico for intrastate gas pipelines within their boundaries, and with 15 states for hazardous liquid intrastate pipelines. If a state authority does not apply for annual certification, inspection, and enforcement activities, all intrastate facilities in that state remain the responsibility of PHMSA.[26]

PHMSA's pipeline inspectors and the nine interstate agents conduct periodic integrated inspections of interstate pipelines. These inspections look at the entirety of an operator's pipeline safety approach, including ensuring operators meet operator qualification requirements. PHMSA conducts its integrated inspections on individual pipeline segments, known as inspection systems. These inspection systems are comprised of one or more smaller pipeline units.[27] PHMSA's Office of Pipeline Safety employs over 200 staff across headquarters and 5 regional offices, with about 130 of those staff involved in inspections and enforcement of interstate pipelines.

As part of oversight activities, PHMSA also collects a range of data on pipeline materials and corrosion prevention through annual operator reporting and incident reports, and during its integrated inspections. The data describe various characteristics of the pipeline, including the type of material (e.g., steel, plastic, or composite), the diameter of the pipe, and when it was installed.[28] The corrosion prevention data include information

[25] 49 U.S.C. § 60105. States may adopt additional or more stringent standards so long as they are compatible with federal regulations. 49 U.S.C. § 60104(c).

[26] Under a certification, each state must file an annual progress report with PHMSA that includes information on all pipeline operators, incidents, and state-conducted inspection and enforcement activities. 49 U.S.C. § 60105(c).

[27] As defined by PHMSA, in 2016, the average length of a pipeline unit was 284 miles, while the average length of a pipeline inspection system is 706 miles. This length includes pipeline mileage and estimated mileage for facilities such as compressor stations, and underground storage facilities.

[28] PHMSA defines composite as pipe that consists of two or more dissimilar materials layered together to be stronger than the individual materials. Examples include, but are not limited to, fiber reinforced plastic pipe, steel reinforced thermoplastic pipe, and metallic composite pipe. (Instructions for Form PHMSA F 7100.2-1).

on whether the pipeline is coated and cathodically protected, and other characteristics associated with corrosion.

Pipeline Operators Use Steel, Plastics, and Various Corrosion Prevention Technologies, Which Have a Range of Benefits and Limitations

Nearly All Federally Regulated Pipelines Are Constructed of Steel or Plastic, Which Involve Various Benefits, Limitations and Costs

The vast majority (over 95 percent) of U.S. gas and hazardous liquid pipeline miles that PHMSA regulates are constructed of either steel or plastic, with relatively minor use (less than 5 percent) of other materials, including composites and iron, according to our analysis of PHMSA data from 2015. (See table 2.) The extent of steel and plastic use varies in different parts of the pipeline network (gathering, transmission, and distribution) due to operating conditions and other factors, as discussed below. For example, nearly all pipeline miles in the transmission network consist of steel pipelines, while plastic pipelines represent over half of pipeline miles in the gas distribution network. In addition, the ratio of these materials within the network has changed over time. PHMSA's data indicates that, from 2010 through 2015, the percentage of plastic pipeline miles in the gas distribution network increased from 58 to 62 percent. According to industry stakeholders we interviewed, the vast majority of new and replacement distribution pipes are made of plastics.[29]

[29]To obtain information on pipeline materials and corrosion prevention technologies, we selected and interviewed a sample of eight pipeline operators and eight expert stakeholders and asked them about the use of these materials and technologies. Because broad agreement existed across the operators and expert stakeholders for many of these topics and our sample was non-generalizable, we used indefinite quantifiers to describe the responses where appropriate, as defined in our methodology. See appendix II for more details.

Table 2: Percentage of Gas and Hazardous Liquid Pipeline Network Miles by Material, 2015

Material type	Gathering[a]	Transmission[b]	Distribution[c]
Steel	95%	99%	35%
Plastic	4%	0.3%	62%
Composites (consists of two or more dissimilar materials layered together)[d]	0%	0.002%	N/A
Other (iron, copper, and other materials)[e]	1%	0.6%	3%

Source: GAO analysis of Pipeline and Hazardous Materials Safety Administration (PHMSA) data. | GAO-17-639

Note: Values may not total to 100 percent due to rounding.

[a]PHMSA only collects data on federally regulated gathering pipelines. PHMSA estimates that only 5 percent of gas gathering pipeline miles and about 10 percent of hazardous liquid pipelines are regulated.

[b]Includes both gas transmission and hazardous liquid transmission pipelines.

[c]Distribution refers to distribution of gas.

[d]PHMSA data on composite materials are only reported separately from materials classified as "other" for gas transmission and gas gathering.

[e]For hazardous liquids gathering pipelines, PHMSA classifies pipeline materials as "steel" or "non-steel." In 2015, there were 27 miles of non-steel hazardous liquid gathering miles reported to PHMSA by pipeline operators, which are classified as "other" in this table. These miles made up less than 1 percent of all reported gathering miles.

The composition and use of these materials can vary widely:

- *Steel*: Steel is widely used in the gathering, transmission, and distribution segments of the pipeline network, and can be manufactured in various grades (strengths). Each grade refers to a specific strength range and chemical composition of iron and a small percentage of various elements, including carbon and manganese. According to operators and expert stakeholders we interviewed, the grade of steel used in a pipeline depends on a variety of factors, including the required operating pressure to propel the product through the pipeline, the operating environment, and cost. PHMSA regulations establish a design formula to determine the maximum allowable operating pressures for pipelines constructed from various grades of steel.[30] In practice, steel's strength to withstand high operating pressures and other design characteristics generally facilitate its use across all portions of the pipeline network. Corrosion-resistant steel alloys, such as stainless steel, are used in limited

[30]49 C.F.R. § 192.105(c) (gas); 49 C.F.R. § 195.106 (hazardous liquids).

circumstances due to their high costs, according to a few operators and expert stakeholders. Such alloys are used primarily in offshore applications or in limited circumstances to gather particularly corrosive oil or gas products or in high consequence areas.

- *Plastic*: Plastics are used primarily in gas distribution pipelines, along with a smaller percentage of gathering pipelines. Specifically, operators and expert stakeholders identified polyethylene, which is a plastic used to make many common household products such as bottles and food wrap, as the most commonly used plastic, particularly within the gas distribution network. According to PHMSA data, 99 percent of plastic pipeline distribution network miles are composed of polyethylene. An operator and industry stakeholder also identified polyamides, a nylon-woven plastic, as an emerging pipeline material due to its increased strength, although it is currently only used in less than 1 percent of distribution pipeline miles according to PHMSA data. Current PHMSA regulations permit plastic pipelines to be used at pressures up to 100 psi, with exceptions for certain polyethylene pipelines that can be used up to 125 psi, and certain polyamides up to 200 psi.[31] In 2015, PHMSA proposed changes to these regulations that would allow use of polyamide plastic pipelines at even higher operating pressures.[32]
- *Composites*: Although composites, such as fiberglass, fiber-reinforced plastic, and other materials represent a very small portion of the nation's pipeline network miles, two expert stakeholders reported increasing use of the these materials primarily in gathering. For example, one expert stakeholder said that fiber pipe was starting to be adopted in place of steel for gathering in certain situations because it can be used at higher pressures than polyethylene. Operators and expert stakeholders also told us that composite pipes are generally corrosion-resistant and are easier to transport and install, as they may come in spoolable reels and do not require welding. However, PHMSA officials noted that the design and materials for composite pipelines can vary substantially, and there are few applicable standards or requirements for composite materials. Consequently, composite materials need to be vetted individually for each specific use, according to PHMSA. As a result, PHMSA requires operators to obtain special permits to use composite materials, and the maximum allowable operating pressure can vary depending on the type of

[31] 49 C.F.R. § 192.123.

[32] 80 Fed. Reg. 29263 (May 21, 2015). This proposed rule has not yet been finalized.

material proposed.[33] From 2010 through March 2017, PHMSA had approved 8 of 14 special permit applications that proposed the use of composite materials in the pipeline network.[34] PHMSA officials stated that the pipeline industry is working to develop standards for these materials, and the industry has petitioned PHMSA to incorporate any such standards into its regulations.

Operators and expert stakeholders identified a variety of benefits and limitations associated with commonly used pipeline materials, such as the ability or inability to accommodate high pressures, and resistance or susceptibility to corrosion. More specifically, for steel, plastic, and composite pipelines, they identified trade-offs among these materials, as detailed in table 3. For example, while steel provides strength and can accommodate higher operating pressures compared to plastic and composites, it is susceptible to corrosion and requires the use of corrosion protection technologies. In contrast, plastic and composite materials are generally corrosion-resistant, except when metallic components are used in some composite pipes that are reinforced with steel. However, NTSB officials noted that assessing the integrity management of plastic pipelines can be challenging because there are limitations in established technologies currently available to assess flaws in plastic pipe or certain joints, and the industry has limited data regarding the long-term reliability of plastic pipelines and associated components.

[33]Special permits are authorized by statute in 49 U.S.C. § 60118(c) and the application process is set forth in 49 C.F.R. §190.341.

[34]PHMSA officials noted that the agency has denied two applications, two applications were withdrawn, and two applications were under review as of March 2017.

Table 3: Operator- and Expert Stakeholder-Identified Benefits and Limitations of Pipeline Materials

Material type	Benefits	Limitations
Steel	• Greater strength than nonmetallic materials to accommodate high pressures • Greater resistance to third-party damage (such as damage due to digging or excavation) than plastics, composites • Only cost-effective material for higher transmission pressures and diameters	• Susceptible to corrosion and requires corrosion prevention technology such as coatings, which increases costs • Steel generally costs more than plastic • Higher installation costs than plastic • Higher costs to weld steel than to fuse plastic
Plastic	• Corrosion resistant • Installation is simpler and quicker than steel, reducing cost • Plastic material generally costs less than steel	• Lacks strength for use at higher operating pressures and diameters • More susceptible to third-party damage than steel
Composites[a]	• Corrosion resistant • Installation is simpler and quicker than steel, reducing cost • Some composites are better able to withstand pressure than plastic	• Generally lack strength for use at higher operating pressures, compared to steel • Difficult to join with other pipelines

Source: GAO analysis of operator and expert stakeholder information. | GAO-17-639

Note: The table above includes frequently identified benefits and limitations from analysis of interviews with eight pipeline operators and eight expert stakeholders.

[a]The Pipeline and Hazardous Materials Safety Administration defines composites as pipe that consists of two or more dissimilar materials layered together to be stronger than the individual materials.

Although several operators and expert stakeholders told us that steel generally costs more per unit than plastic, the relative costs of pipelines made of these materials depend on an interplay of factors, including pipeline design, installation, and maintenance.[35]

- *Design*: According to almost all the operators and expert stakeholders we interviewed, the design of a pipeline, including the intended operating pressure, is a significant factor in the selection of a pipeline material, and a majority of operators and expert stakeholders we interviewed said that pipeline diameter and wall thickness can affect the cost of pipeline materials. Specifically, at lower diameters and pressures, such as in distribution and some gathering pipelines, plastic often has a cost advantage, while in the larger diameters and pressures of transmission pipelines, steel is the only cost-effective material. Higher diameters and pressures necessitate increasingly

[35]A majority of operators and expert stakeholders provided only qualitative, rather than quantitative, information on the cost of materials.

thicker walls, which makes plastic cost prohibitive, according to operators and expert stakeholders. Steel, in contrast, can be manufactured at higher grades, allowing thinner but stronger walls, or at lower grades producing thicker, but lower-strength walls. Operators and experts told us that because pipeline steel is purchased by weight, the pipeline industry has increased its use of higher grade, thinner-wall steel in recent years to reduce material costs while maintaining higher strengths.

- *Installation*: Operators and expert stakeholders we interviewed told us that installation is a major cost component for pipelines, though these costs are generally higher for steel than other materials. Generally, in circumstances where either steel or plastic could be used, operators and expert stakeholders told us that installation of steel is more expensive than plastic. For example, a steel pipeline requires that a trench be dug and prepared before installation, while plastic can often be plowed into the ground without preparation, reducing time and expense. Joining of pipe sections, by either welding (steel) or fusing (plastic) is an important component of installation and can also add to the cost. Operators and expert stakeholders also told us that welding steel is more difficult and time consuming than fusing plastic, adding to the cost. Operators and expert stakeholders also noted that composite material pipeline segments can be challenging to join with other segments in the pipeline network.
- *Maintenance*: For steel pipelines, over half of the operators and expert stakeholders we interviewed stated that material-specific maintenance costs to prevent corrosion can affect the overall life-cycle cost of the pipeline. For example, several operators and expert stakeholders said that while using higher grade steel allows operators to reduce overall steel material expense, higher grade steel pipelines have thinner walls and may have less corrosion allowance—that is, the amount of material that may corrode without affecting the integrity of the pipeline. As such, higher grade steels can result in higher maintenance costs associated with monitoring and corrosion prevention, according to one expert stakeholder. Operators and expert stakeholders noted that while plastic pipelines do not have corrosion prevention maintenance costs, they are more susceptible than steel to third-party damage that requires repair.

Most Federally Regulated Pipelines Use Corrosion Prevention Technologies, Which Involve Various Benefits, Limitations, and Costs

External Corrosion Prevention Technologies

Operators and expert stakeholders we interviewed stated that the primary technologies to prevent external corrosion are coatings and cathodic protection, and these tools are widely used across the pipeline network. As previously noted, PHMSA regulations require external coatings and cathodic protection for all metallic pipes installed beginning in 1971.[36] According to our analysis of PHMSA operator-submitted data, operators have externally coated and cathodically protected over 96 percent of steel gathering and transmission pipelines and 85 percent of steel distribution pipelines across the federally regulated pipeline network. A lower percentage of steel distribution pipelines are externally coated and cathodically protected because distribution networks in many areas were installed before 1971. According to PHMSA officials, these older, unprotected steel distribution pipelines are often replaced with plastic, which reduces the total mileage of unprotected steel distribution pipelines.

Coatings and cathodic protection offer important safety benefits to protect steel pipelines from external corrosion, but these technologies also have limitations in their effectiveness. Operators and expert stakeholders generally agreed that coatings and cathodic protection are complementary technologies and function most effectively when used together.[37] Specifically, coatings provide a protective barrier to the pipeline surface, and if this barrier is compromised, cathodic protection delivers an electric current to the exposed area to inhibit corrosion. In addition, over half of the operators and expert stakeholders we interviewed stated that these technologies are also used to prevent stress corrosion cracking in steel pipelines. However, these technologies have some limitations. For example, according to operators and expert

[36]49 C.F.R. § 192.455.

[37]See also, Baker, Jr., Michael and Fessler, Ronald R., *Pipeline Corrosion, Final Report to U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety*, DTRS56-02-D-70036 (November 2008).

stakeholders, some coatings can be difficult to install and apply in the field and all coatings can deteriorate over time. They also said that a variety of different coatings exist and their effectiveness can vary based on operating factors, particularly in extreme temperatures which can disbond coatings from the pipe surface.[38] Operators and expert stakeholders also told us that the effectiveness of cathodic protection can be limited by "shielding," which occurs when the electrical current is obstructed from reaching the pipeline by obstacles such as rocks, failed coatings, or interference from nearby electric power cables.[39] (See table 4.)

[38]According to recommended practices published by NACE International, formerly the National Association of Corrosion Engineers (NACE), and incorporated into PHMSA's regulations by reference, factors that are considered when selecting an external pipe coating include the type of environment, operating temperature on the existing pipelines, cost, and installation requirements. See NACE, *Standard Practice Control of External Corrosion on Underground or Submerged Metallic Piping Systems*, NACE SP0169-2013 (Houston, TX: 2013).

[39]In its report on the 2012 Sissonville pipeline incident, NTSB noted that various materials—such as tree roots, rocks, and disbonded coatings—can provide shielding of cathodic protection. NTSB concluded that the coarse rock covering the pipe most likely shielded the pipe from the cathodic protection current and contributed to the corrosion that caused the pipeline incident. NTSB/PAR-14/01, PB2014-103977.

Table 4: Operator- and Expert Stakeholder-Identified Benefits and Limitations of Various External Corrosion Protection Technologies

External corrosion protection technology	Description	Benefits	Limitations
Fusion-bonded epoxy coating	Powder epoxy coating heat-bonded to a pipeline. Standard modern coating.	• Does not block cathodic protection if the coating fails • High adhesive rate • Durable • Protects against stress corrosion cracking	• Effectiveness decreases at extreme temperatures • Can be difficult to apply in the field
Three-layer polyethylene coating	System composed of a fusion-bonded epoxy coating, adhesive and outer layer of polyethylene plastic.	• Resistant to soil stress • Can be used at higher pressures • Effective in wet environments	• May block cathodic protection if bonding fails • Effectiveness decreases at extreme temperatures • May have higher costs relative to other coatings
Tape wrap coating	Tape composed of plastic or other material wrapped around a pipeline and welds.	• Operators and expert stakeholders we interviewed did not identify any benefits of tape wrap coating	• May block cathodic protection if bonding fails • May be associated with stress corrosion cracking • May have an overall higher failure rate • Can be challenging to apply
Cathodic protection	System that applies a small electrical current onto a pipeline.	• Protects against external corrosion • Complements coating	• Rocks, stray current from nearby electric power cables, or failed coatings can block cathodic protection • Requires access to electrical power • Costs increase as coatings age

Source: GAO analysis of operator and expert stakeholder information. | GAO-17-639

Note: The table above includes frequently identified benefits and limitations from analysis of interviews with eight pipeline operators and eight expert stakeholders.

Operators and expert stakeholders we interviewed identified a variety of factors that can affect the cost of these technologies. According to operators and expert stakeholders, coatings and cathodic protection are generally a cost-effective way to protect steel pipelines against external corrosion and stress corrosion cracking, and operators and expert stakeholders said that coatings and cathodic protection are a relatively small portion of total pipeline cost.[40] According to operators and expert

[40]Peabody, A.W, *Peabody's Control of Pipeline Corrosion*, Ch.15: Economics, 2nd Ed. NACE International (2001).

stakeholders, factors that can affect the overall cost of coatings include the type of coating; application costs, including application of coating to pipeline joints in the field after welding; and maintenance of the coating (which requires excavation, inspection, and repair). Factors that can affect the overall cost of cathodic protection include initial installation of equipment; the cost of providing power, including in remote locations where power is not readily available; the need to increase electrical power over time to protect the pipeline as coatings degrade; and on-going monitoring and maintenance.

Internal Corrosion Prevention Technologies

Operators and expert stakeholders also identified internal corrosion prevention technologies along with their benefits and limitations.[41] (See table 5.) According to PHMSA, many interrelated technical factors can affect the likelihood, aggressiveness, and location of internal corrosion.[42] For example, certain types of internal corrosion are caused by chemical reactions between the material being transported and the wall of the pipeline. In these cases, pipeline operators stated that they typically inject "inhibitors"–chemical compounds that inhibit these chemical reactions. The type of chemical compound injected will depend on the type of product, cost, availability, and environmental effect.[43] In other cases, pipeline operators stated that they can use devices known as "cleaning pigs." Cleaning pigs are electronic devices with cleaning brushes attached to them that run through the inside of the pipeline to scrub it and remove water and other contaminants from the pipeline. Operators and expert stakeholders also emphasized the importance of controlling pipeline-operating conditions to prevent internal corrosion, including maintaining sufficient flow and velocity of products in the pipeline to reduce the accumulation of water and contaminants.

[41]PHMSA officials told us that they do not collect data on the use of internal corrosion prevention technologies because they are not widely used and their application is often customized to the specific product in the pipeline.

[42]In 2007, PHMSA polled its senior corrosion experts and other subject matter experts to obtain feedback on internal corrosion topics, including factors affecting internal corrosion. Among the factors contributing to internal corrosion, they noted that the product transported, the operating pressure, the presence of microbes, and other operating conditions can contribute to internal corrosion. See U.S. Department of Transportation, *Internal Corrosion Control: A Regulatory Requirements Adequacy Review* (Washington, D.C.: Dec. 31, 2007).

[43]DTRS56-02-D-70036.

Table 5: Operator- and Expert Stakeholder-Identified Benefits and Limitations of Various Internal Corrosion Prevention Technologies

Internal corrosion technology	Description	Benefits	Limitations
Additives (i.e., biocides and inhibitors)	Chemical compounds inserted into a pipeline that limit reactions that cause internal corrosion	• Biocides eliminate microbes in the pipeline • Inhibitors block chemical reactions in the pipeline	• Can be relatively expensive compared to other technologies • Require multiple, periodic application • May affect product quality • May have negative environmental effects
Cleaning devices (known as "cleaning pigs")	Specialized devices with brushes that are inserted into the pipeline to help eliminate water or debris that can cause corrosion	• Remove water or debris • Complementary with additives and biocides	• Require the installation of infrastructure to insert and remove pigs in the pipeline • Some pipelines cannot accommodate cleaning devices • May require reduced flow rate during use
Dehydration systems	Devices that remove moisture from and reduce the dew point in products	• Effective at removing moisture from gas	• Can be relatively expensive compared to other technologies • Recurring operational costs
Internal coatings and liners	Plastic liners or treatments that provide a barrier between the internal surface of a pipe and the transported products	• Can be effective in highly corrosive environments • Can improve flow velocity	• Can be relatively expensive compared to other technologies • Can be challenging to install or repair • Liners are not always compatible with cleaning devices
Monitoring tools (such as in-line inspection devices)	Electronic tools that are inserted into the pipeline and provide information on the structural condition	• Provide real-time update on the status of corrosion and integrity of the pipeline	• Can be relatively expensive compared to other technologies • Some pipelines cannot accommodate monitoring tools

Source: GAO analysis of operator and expert stakeholder information. | GAO-17-639

Note: The table above includes frequently identified benefits and limitations from analysis of interviews with eight pipeline operators and eight expert stakeholders.

A variety of factors affect the cost of internal corrosion prevention technologies. First, operators and expert stakeholders noted that labor and equipment, such as installing infrastructure to launch and receive the cleaning pigs, can be expensive. Second, operators and expert stakeholders noted that the use of cleaning pigs can temporarily reduce the flow rate of the product so, while not necessarily affecting costs, the revenue of the pipeline operator could be affected by the use of the technology. Third, the extent of the internal corrosion threat can require greater use of inhibitors and cleaning pigs, thereby increasing the costs for the pipeline operator. Similar to coatings and cathodic protection, only two of the operators and expert stakeholders we interviewed provided specific information on the costs of these technologies, and generally noted that the costs of these technologies vary with the type of technology used.

Selected Pipeline Operators Reported Using a Variety of Sources for Pipeline Corrosion Training and Identified Challenges Ensuring Personnel Are Qualified

Pipeline Operators and Unions Use Internal and Third-Party Corrosion Training for Personnel

Gas and hazardous liquid pipeline operators use several sources to train personnel on pipeline corrosion, including in-house training and third-party programs, according to our interviews with eight operators and nine other stakeholders, including unions, training providers, and industry associations. According to operator qualification regulations from PHMSA, operators have discretion to determine the training approaches they provide to ensure personnel are qualified.[44] Operators are also responsible under the regulations for ensuring any contractor personnel they hire for operations and maintenance tasks are qualified, even if the contractors are already trained for those tasks. The operators we interviewed told us that PHMSA's operator qualification regulations provide flexibility to tailor their operator qualification program and any corresponding training program to their operational needs. In practice, operators and stakeholders told us this flexibility allows operators to use several training sources and approaches to supplement their operator qualification plans.

[44] 49 C.F.R. § 192.805(h) and 49 C.F.R. §195.505(h).

- *Internal training programs*: Operators and stakeholders noted internal training programs vary across companies, depending on factors such as the type of pipeline, environment, and staff resources. All of the eight operators we spoke with provided in-house training programs depending on the needs of the company. Six of the eight operators said their in-house training included methods such as on-the-job training, mentoring programs, apprenticeships, and online training. Such training programs teach skills related to corrosion prevention such as applying pipe coating, conducting cathodic protection surveys, and examining the soil surrounding the pipe. Operators we interviewed also identified different approaches for retraining staff to maintain qualification. For example, one hazardous liquid operator requires all corrosion technicians and contractors to take training and assessments every 3 years, while another hazardous liquid operator stated that it assigns retraining intervals from 2 to 6 years based on the risk associated with each task.
- *Third-party training providers*: In addition to internal training, operators also frequently use third-party training providers, according to operators and stakeholders we interviewed. All eight operators and six stakeholders said operators typically use third-party providers, such as industry associations and colleges, for general corrosion training programs. For example, NACE International, formerly the National Association of Corrosion Engineers (NACE), offers two training programs on corrosion prevention technologies: a series of courses on pipeline coatings and a series of courses on cathodic protection. All eight operators said they use NACE training, and six operators said they consider NACE certifications to be the industry standard for hiring corrosion personnel. Several operators also reported that their personnel attended the Appalachian Underground Short Course, which offers a variety of corrosion-related courses at four levels of difficulty, along with a separate course on pipeline coatings. Operators also cited Purdue University's Corrosion College and the Midwest Energy Association's EnergyU as frequently used sources of corrosion training.[45]
- *Industry association guidance*: Operators also make use of industry associations' guidance for training, according to one operator and three stakeholders. For example, operators may consult practices from the American Society of Mechanical Engineers, which offers guidance on training programs and identifies 170 tasks personnel

[45]Midwest Energy Association is a trade association that provides training and events to utility and energy distribution companies.

should be able to perform, including corrosion-related tasks.[46] Operators also use recommended practices from the American Petroleum Institute, including guidance that identifies 99 pipeline operational safety tasks, such as corrosion-related tasks.[47]

- *Union training for members*: Unions are another source of pipeline corrosion training. Two of the three unions we spoke with provide pipeline training to their members related to corrosion prevention. For example, one union representing contractors uses a third party to provide training for its members on pipelines using its national training fund. The course does not specifically cover corrosion but addresses pipe damage and abnormal operating conditions such as corrosion. Staff from a second union that represents contractors said that they train members to their own national standards for specific corrosion-related tasks, such as those related to pipeline coating and cathodic protection. The staff stated that personnel must have completed the union's pipeline technical course to be dispatched to job sites. However, operators must separately ensure the personnel are qualified to perform the specific tasks they are contracted to complete, as discussed below. A third union, which represents operator employees, said that while the union does not provide formal training, its members receive training from the operators.

Stakeholders Stated PHMSA's Operator Qualification Requirements May Present Challenges for Pipeline Operators, Contractors, and PHMSA

Although PHMSA's operator qualification regulations allow operators flexibility in training approaches, operators and contractors identified several challenges. In particular, operators told us that they rely on contractors for a variety of corrosion-related tasks, in part because of limited resources, and a need for specialized expertise. Because approaches to training and operator qualification vary across the industry, operators have difficulty verifying contractor qualification, and contractor training and qualification may not transfer to various operators.

- *Operator challenges*: Operators and stakeholders identified challenges in ensuring that contractor personnel have the skills and abilities to carry out various corrosion-related tasks associated with PHMSA's operator qualification regulations, known as covered tasks. Although, according to the regulations, operators are responsible for

[46]American Society of Mechanical Engineers, *Pipeline Personnel Qualification: ASME Code for Pressure Piping,* ASME B31Q-2016 (New York, NY: Aug. 30, 2016).

[47]American Petroleum Institute, *Recommended Practice for Pipeline Operator Qualification, RP 1161* (Washington, D.C.: January 2014).

ensuring their contractors are qualified, seven of the eight operators we spoke with said verifying contractor qualifications was challenging. For example, an operator we interviewed said even if a contractor has completed a training program from a union or third-party provider, the contractor may not be trained or have the experience to fulfill the operator's needs and the operator may need to separately evaluate the contractor's ability to perform covered tasks. In addition, three operators and two unions said qualification evaluations do not always accurately reflect contractors' skills and abilities. For example, one operator said contractor personnel may have passed an evaluation to install cathodic protection, but they may not have been trained to complete important parts of the installation, such as the use of specialized tools to measure electrical current.

- *Contractor challenges*. Operators and stakeholders also said contractors' training and qualifications are not always transferrable, though perspectives on the severity of the challenge and approaches to address it varied. Three operators and one union stated that an evaluation is not always portable to different companies, which one union said can be a barrier for contractors to obtaining work. For example, one operator said it requires contractors to undergo training and evaluations from specific, third-party providers to demonstrate they are qualified to perform 31 specific covered tasks related to corrosion prevention in their operator qualification plan and noted that the operator does not accept contractors with qualifications from other providers. Furthermore, three operators we interviewed noted that even if contractors have been previously evaluated by the operator, they may need to be retested for each covered task by the same operator or by a third-party accepted by the operator.

The two unions representing contractors we spoke with had different perspectives on the portability of evaluations and related training.[48] One union representing contractors said lack of portability was a challenge for its members, who may have to take duplicative training and might lose income while completing an evaluation before starting a job. Another union representing contractors said that while each operator usually prefers its own internal training methods, portability was not a significant issue for its members.

[48]The third union we interviewed represented direct employees of utility companies, rather than contractors.

Operators and other stakeholders we spoke with identified mechanisms under way to address these challenges. Six pipeline operators told us they currently rely on third-party companies to facilitate the verification and portability of qualifications in the pipeline industry. For example, one training vendor stated that it maintains an operator qualification program for over 140 pipeline operators across the country. This vendor said it customizes covered tasks' lists based on each client's needs, though some tasks are common, such as those related to coating and cathodic protection. The vendor said operators may hire it to conduct on-site evaluations to qualify personnel and train operator staff to conduct evaluations. Stakeholders and operators also identified broader solutions to overcome these challenges across multiple operators. For example, one industry organization representing hazardous liquid pipeline operators said there is currently an industry initiative examining challenges related to the portability of training.

In addition to the above challenges operators and stakeholders cited, PHMSA has taken steps to update its regulations related to corrosion prevention training. In July 2015, PHMSA proposed changes to its regulations through the rulemaking process to provide additional direction on pipeline training and operator qualification.[49] More specifically, PHMSA proposed to clarify topics unaddressed in the initial version of these regulations published in 1999.

- First, as noted above, PHMSA's regulations identify training as one option to ensure personnel qualification, but operators have discretion to determine the extent of training to provide. The proposed changes to PHMSA's existing operator qualification regulations would, among other things, require operators to provide training for personnel who perform operator-defined covered tasks, though operators would have discretion in determining what training to provide for employees and contractors covered by the regulations.
- Second, PHMSA has noted that since the current regulations are not prescriptive, the resulting flexibility makes it difficult to measure an operator's compliance with the rule.[50] Moreover, PHMSA officials said that operators do not always review their covered tasks, evaluations,

[49]80 Fed. Reg. 39916 (July 10, 2015).

[50]80 Fed. Reg. 39916 (July 10, 2015).

and procedures to ensure they are effective.[51] The proposed changes would require pipeline operators to evaluate the effectiveness of their operator qualification program and retain records of these evaluations.

- Third, the current operator qualification regulations cover activities on pipelines after they are installed, but there are no requirements to cover new construction tasks. As a result, operators are not required to ensure that personnel employed or contracted to construct new pipelines meet specific qualifications to perform construction tasks. The proposed changes would expand the scope of the operator qualification regulations to cover new pipeline construction and other currently uncovered tasks.

PHMSA issued a final rule in January 2017 addressing other pipeline safety issues considered in the 2015 proposed changes, but it did not issue a decision on the proposals related to the above topics.[52] Specifically, as part of the final rule, PHMSA noted that it expects to publish an additional final rule on operator qualifications in the near future, after it considers and evaluates comments received from stakeholders.

PHMSA Uses Data on Pipelines and Corrosion Prevention to Prioritize Inspections, but Lacks a Process to Assess and Validate the Effectiveness of Its Approach

PHMSA uses data on pipelines and corrosion collected from operators in its Risk Ranking Index Model (referred to as RRIM) to determine the frequency of PHMSA's inspections of operators based on threats to pipeline integrity, such as ineffective coatings. In recent years, PHMSA has taken steps to improve the quality of the data used in RRIM, including reviewing operator-reported data for outlier values. PHMSA officials designed RRIM using their professional judgments, and they did not document the rationale or justification for key decisions, including the selection of threat factors and their associated weights. Moreover, PHMSA has not used data to assess the model's overall effectiveness and lacks a process to do such an evaluation. Without documentation and a data-driven evaluation process, both of which are consistent with federal management principles, PHMSA cannot demonstrate the effectiveness of RRIM in allocating PHMSA's limited inspection resources according to pipeline threats or targeting its limited resources to the greatest threats.

[51] In our interviews, operators identified a variety of approaches that they use to measure training effectiveness.

[52] 82 Fed. Reg. 7972 (Jan. 23, 2017) (codified at 49 C.F.R. Parts 190, 191, 192, 195 and 199).

PHMSA Uses Data on Pipelines and Corrosion Prevention to Prioritize Inspections

Since 2011, PHMSA has used data on pipelines and corrosion prevention, along with other data elements, in a risk ranking model to prioritize pipelines for inspection and manage its inspection resources. The purpose of PHMSA's RRIM is to generate a risk score for each federally inspected pipeline and help determine the frequency of inspection.[53] RRIM incorporates data on a variety of pipeline characteristics, which PHMSA calls threat factors, including a few associated with material and corrosion failures. Those threat factors include:

- steel pipe that lacks a protective external coating, also known as "bare steel;"
- steel pipe that was coated ineffectively, in such a way that the external coating may no longer adhere to the pipe; and
- steel pipe that was manufactured using a technique common from the 1920s until the 1970s, known as low frequency electric-resistance welding, that is susceptible to catastrophic failure and certain types of corrosion.

PHMSA inspectors collect these data from operators during integrated inspections for each pipeline segment, or unit, they inspect. PHMSA officials said RRIM is designed to incorporate various threats and is not limited to material or corrosion threats. Other threat factors that PHMSA uses in RRIM include commodity type, recent significant incidents, and recent enforcement actions. According to PHMSA officials, integrated inspections are tailored to each operator and include reviews of operator maintenance, repair, and other records and visits to pipeline locations to assess cathodic protection or observe other activities.[54]

[53]PHMSA inspects interstate gas transmission and hazardous liquid pipelines, which represent approximately 20 percent of the federally regulated pipeline network; the remaining 80 percent, which includes intrastate pipelines, are inspected by states' pipeline safety offices. As part of its pipeline safety program, PHMSA provides guidance to state partners on how to use a risk-based approach to prioritize inspections.

[54]According to PHMSA, integrated inspections combine several discrete inspection "types" (e.g., Unit Inspections, Operations and Maintenance Procedure Inspections, Integrity Management Inspections, etc.) into a single inspection that provides an integrated evaluation of an operator's safety management programs. PHMSA prioritizes integrated inspections on specific areas based on system-specific risk information in order to apply PHMSA inspection resources to programs, geographic areas, and threats that pose higher risks.

On an annual basis, PHMSA uses RRIM to calculate a risk score for each pipeline unit to determine the frequency of integrated inspections. PHMSA assigns a weight to each threat factor in RRIM, based on data the agency collects. For example, PHMSA assigns a weight of 2 to pipeline units where operators report that ineffective coating is present, as shown in table 6. The weights are then added together and multiplied by the consequence index of the unit.[55] The resulting number is the unit risk score, which is averaged across the units that comprise each inspection system, which is the level at which PHMSA conducts integrated inspections. The inspection system's risk score determines whether the system is assigned to the high, medium, or low risk tier, and inspected at least every 3, 5, or 7 years, respectively.

Table 6: Selected Threat Factors and Weighting Used in the Risk Ranking Index Model of the Pipeline and Hazardous Materials Safety Administration (PHMSA), 2016

Threat factor	Description	Weighting[a]
Unit miles	The number of miles in each pipeline unit, which is the administrative division that PHMSA uses to manage its oversight of the pipeline network.	Weighted 0-3 based on the unit miles in proportion to total network miles.
Pre-1970 low frequency electric resistance welding miles	The number of unit miles that were welded using low frequency electric-resistance welding prior to 1970, which is a risk factor for corrosion.	Weighted 0-3 based on the proportion of pre-1970 low frequency electric resistance welding miles to total network miles.
Enforcement	Enforcement actions over the last 7 years that involved the pipeline unit.	Weighted 0-3 based on type of enforcement action, if any.
Notification	Notifications received by PHMSA of construction or acquisition involving the pipeline unit.	Weighted 2 for construction projects, 3 for acquisitions, or zero if none.
Commodity	The product transported in the pipeline unit, such as hazardous liquids or natural gas.	Weighted 1-6 depending on the type of commodity.
Bare pipe mileage	The number of unit miles that lack a protective external coating, which is a risk factor for corrosion.	Weighted 0-2 based on the proportion of bare pipe to unit miles.
Ineffective coating	The number of unit miles where the protective external coating may not adhere to the pipe, which is a risk factor for corrosion.	Weighted 2 if ineffective coating is present, or zero if none.
Significant incidents	Significant incidents, such as those involving a fatality, injury, or $50,000 or more in total costs, over the last 5 years that involved the pipeline unit.	Weighted 0-10 based on the number of incidents and other factors.

Source: GAO analysis of PHMSA information. | GAO-17-639

[a]Within a given threat factor, greater weights indicate higher relative risks.

[55]The consequence index is a PHMSA formula that calculates a value based on specific characteristics associated with each unit, including pipe diameter, commodity type, and whether the unit is located in a high consequence area.

Annually, PHMSA officials use RRIM to identify inspection system priorities for the next year, based on the risk tier and the amount of time since the system's most recent inspection. Each year PHMSA inspects a portion of the total number of inspection systems, which in 2016 totaled 655 systems. For example, in 2016, PHMSA used RRIM to prioritize a list of 79 systems to be inspected in 2017. Of these systems prioritized for inspection, 29 percent were considered high risk, 53 percent were medium risk, and 18 percent were low risk. In addition, based on the criteria PHMSA established for inspecting high, medium, and low risk systems at least once every 3, 5, and 7 years, respectively, each of these 79 systems were due for inspection. PHMSA officials said this approach allows them to allocate inspection resources to pipelines considered higher risk, while ensuring that all inspection systems are inspected at least every 7 years. PHMSA officials noted that a risk-based inspection approach is necessary given the size of the federally regulated pipeline network and the number of its inspection staff.[56]

PHMSA officials said RRIM is the primary tool they use across their regional offices and interstate agents to prioritize and schedule inspections but said they also consider input from regional inspection staff as part of this process. Each year, PHMSA headquarters officials provide the list of inspection priorities generated by RRIM to the regional offices, and inspectors have the opportunity to review the list and provide feedback. Regional inspectors told us that during these reviews they use their knowledge of local operators and pipelines to recommend that certain pipeline units be given higher or lower priority than they are ranked by RRIM. Regional inspectors said RRIM is generally effective in prioritizing inspections, but there are threats that it may not capture, such as the management experience of an operator, or whether there has been recent public concern regarding a particular pipeline. For those interstate pipelines inspected by states' pipeline safety offices designated as interstate agents, state officials said they also have the opportunity to review PHMSA's inspection priorities and suggest additional priorities.[57]

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[56]Our prior work has made recommendations supporting a risk-based approach to PHMSA's oversight. See GAO, *Gas Pipeline Safety: Guidance and More Information Needed before Using Risk-Based Reassessment Intervals*, GAO-13-577 (Washington, D.C.: June 27, 2013).

[57]State pipeline safety offices designated as interstate agents were responsible for inspecting approximately 12 percent of federally inspected pipeline miles in 2017.

PHMSA Has Taken Some Steps to Improve Data Quality to Enhance Its Risk Ranking Index Model

In recent years, PHMSA has taken steps to improve the quality of the data used in RRIM. In June 2012, the Department of Transportation's Office of Inspector General identified a number of long-standing data management deficiencies at PHMSA that have limited its ability to conduct meaningful analysis to improve its oversight.[58] Among the concerns, the Inspector General found that shortcomings in PHMSA's data management and quality limited the usefulness of operator incident and annual reports in identifying pipeline safety risks.[59] PHMSA officials told us that in recent years they have implemented a number of procedures to limit errors and improve the accuracy of data submitted by operators. For example, under PHMSA's internal data management procedures, officials stated that they review all incident report submissions from operators on a monthly basis to ensure they are complete and to identify outlier data entries. PHMSA officials also said they review a spreadsheet of all unit data that can be confirmed in operator-submitted annual reports and compare data entries with those submitted by operators in prior years to detect data anomalies.

Although PHMSA has taken some steps to improve data quality, PHMSA officials identified other limitations with their current data collection that hinder their ability to enhance the data used in RRIM. Officials stated that RRIM does not include all the threat factors they would like to use because they have not collected certain data at the unit level, which is the level at which the model calculates risk scores. For example, officials said they would like to use data on maximum allowable operating pressure as a threat factor for RRIM, but PHMSA's current data on operating pressure are collected in aggregate at the state level for each operator and not at the unit level. In addition, officials noted that the data do not allow PHMSA to identify the precise location of threats such as ineffective external coating or certain types of welding associated with corrosion, and therefore PHMSA cannot determine whether threat factors are co-located and potentially correlated. To help address this limitation, PHMSA has developed a form that enables inspectors to systematically collect additional data at the unit level during an inspection. While this approach

[58] U.S. Department of Transportation, Office of Inspector General, *Hazardous Liquid Pipeline Operators' Integrity Management Programs Need More Rigorous PHMSA Oversight*, AV-2012-140 (Washington, D.C.: June 18, 2012).

[59] Specifically, the report recommended, among other things, that PHMSA establish additional quality assurance procedures to verify the accuracy of operator annual reports and accident data. This recommendation was implemented in 2013.

could improve the quality of data in RRIM these data will not be immediately available, since the inspection systems are inspected every 3, 5, or 7 years based on their risk score.

To address these limitations, PHMSA has sought to expand its data collection through the National Pipeline Mapping System, a geographic information system managed by PHMSA, which officials said would strengthen the accuracy and precision of the data used in RRIM.[60] In June 2016, PHMSA issued a public notice to expand its information collection authorities to collect pipeline data from operators at a positional accuracy of approximately 100 feet, which is significantly more precise than the pipeline unit, which in 2017 averaged over 200 miles in length.[61] This data collection would include threats associated with corrosion prevention, such as whether the pipe is externally coated, and how the pipe was welded, among other pipeline characteristics. However, in its March 2017 decision memo, OMB declined PHMSA's proposal to collect these additional data, but the memo did not provide a reason for this decision. PHMSA officials said they are evaluating their next steps and plan to propose a revision to their data collection that does not impose excessive burden on stakeholders before PHMSA's current data collection authority expires in 2020.

More broadly, as part of its strategic plan, PHMSA is taking steps to better align its organizational structure with the need for a consistent approach to how it collects, manages, and uses data. In 2016, PHMSA established the Office of Planning and Analytics, whose mission is to support a data-driven approach to PHMSA's oversight by leading strategic planning and analytical projects. According to PHMSA, the establishment of the Office of Planning and Analytics will support PHMSA's efforts to become a data-driven and risk-based safety agency.

[60]The National Pipeline Mapping System is a dataset containing locations of and information about gas transmission and hazardous liquid pipelines and liquefied natural gas plants which are under the jurisdiction of PHMSA. The data are used by PHMSA for emergency response, pipeline inspections, regulatory management and compliance, and analysis purposes.

[61]81 Fed. Reg. 40757-40765 (June 22, 2016).

PHMSA Has Not Documented Its Decisions or Validated the Effectiveness of Its Risk Ranking Index Model

Although PHMSA has taken steps to improve the quality of data used in RRIM, PHMSA did not document key decisions and the rationale used to design RRIM. Specifically, in designing RRIM, PHMSA did not document its rationale for the selection of threat factors and their associated weights, or the thresholds for risk tiers, and the frequency of inspection associated with each risk tier. *Standards for Internal Controls in the Federal Government* state that documentation is necessary to demonstrate the design, implementation, and operating effectiveness of a program.[62] Additionally, OMB's risk analysis principles state that agency risk analyses should be based upon the best available scientific methodologies, information, data, and weight of the available scientific evidence, and that the rationale for the judgments used in developing a risk assessment should be stated explicitly.[63]

PHMSA officials said they used professional judgment to select threat factors, to determine their associated weights, and to establish the risk tiers and inspection frequency, but they did not document the rationale or justification for their decisions, including how, if at all, they used data as part of developing this approach.[64]

- *Selection of threat factors and weights*: PHMSA officials said that certain threat factors, such as mileage of bare pipe and ineffective coating, are generally known in the pipeline industry as problematic, but officials did not document their decisions for how they determined the selected weights or for how, if at all, they used data to develop the values for the weights. The officials said they conducted sensitivity analyses to calibrate the threat factor weights when they designed RRIM in 2012, but did not document these analyses.
- *Thresholds for risk tiers*: Similarly, PHMSA did not document how it established the risk tiers and inspection frequency, or the rationale for those decisions. PHMSA officials consider any inspection system with

[62]GAO, *Standards for Internal Control in the Federal Government*, GAO-14-704G (Washington, D.C.: September 2014).

[63]OMB, *Updated Principles for Risk Analysis*, OMB Memorandum M-07-24 (Washington, D.C.: Sept. 19, 2007).

[64]A 2013 Department of Transportation report found that index risk models, similar to PHMSA's risk model, often use judgmentally determined risk factors and weights, and should be validated using data. See Department of Transportation, *Pipeline Integrity Management: An Evaluation to Help Improve PHMSA's Oversight Of Performance-Based Pipeline Safety Programs* (Washington, D.C.: Oct. 31, 2013).

a score of 30 or more as high risk, more than 5 but less than 30 as medium risk, and less than 5 as low risk. PHMSA officials said the thresholds for the risk tiers were determined based on their professional judgment that 25 percent of inspection systems should be considered high risk, 50 percent medium risk, and 25 percent low risk to ensure a relatively consistent workload across regions. Officials said they determined inspection frequencies of 3, 5, and 7 years based on professional judgment, noting that each inspection system should be inspected at least once every 7 years and that the highest risk systems did not require inspection more than once every 3 years. However, PHMSA did not document the rationale for the decisions made or how, if at all, data informed their decision-making process.

PHMSA officials told us that although they did not document these decisions, which were made based on their professional judgment, they solicit and receive feedback from PHMSA inspectors each year on the list of inspection systems generated by RRIM, a step that serves as a check on RRIM's effectiveness. However, without documentation, the rationale for key decisions and assumptions made as part of designing and implementing RRIM is unclear. For example, RRIM's design places a greater relative weight on longer pipeline units, assuming that longer pipeline segments have greater relative risk than shorter units. In 2016, the average length of a high risk inspection system was 1,841 miles; the average length of a medium risk inspection system was 358 miles, and the average length of a low-risk system was 49 miles. Moreover, in 2016 RRIM assigned approximately 1 percent of all pipeline miles inspected by PHMSA as low risk (7-year inspection cycle) and more than 70 percent as high risk (3-year inspection cycle). While this generally results in more frequent inspections for longer pipeline systems—which may be desirable from PHMSA's perspective—without documentation, the rationale for the chosen mileage weighting and the assumed risk of this factor relative to other factors is unclear.

In addition to a lack of documentation, PHMSA lacks a process that uses data to assess the ongoing effectiveness of RRIM and validate that it appropriately prioritizes inspections. Leading management practices and principles have highlighted the importance of periodic review and evaluation of risk management approaches. Specifically, OMB's risk management principles state that the risk management process must be subjected to regular review to assess potential changes in risks, their likelihood and impact, and deliver assurance that the risk management process remains appropriate and effective.[65] In addition, *Standards for Internal Controls in the Federal Government* states that management should use quality information to make informed decisions and evaluate program performance in achieving key objectives and addressing risks.[66] Similarly, PHMSA's strategic plan includes an objective to use data more effectively to improve its risk-based approach to inspection.

PHMSA officials said they have not established a data-driven process to assess the effectiveness of RRIM because they believe that it has been an effective tool for prioritizing inspections for its staff. The officials said that they conducted sensitivity analyses to calibrate the weights in RRIM when they first designed it in 2012, but did not document those analyses, and they have made periodic changes to RRIM, such as adding threat factors or adjusting weights, based on their professional judgment. However, it is unclear what impact these changes have had on the effectiveness of RRIM, as PHMSA officials could not provide documentation of any analyses to support why these changes were made and their impact on RRIM's results. PHMSA officials noted that the Office of Planning and Analytics has begun evaluating potential strategies to improve RRIM's risk-modeling capabilities, and to examine how the officials could use existing data to validate RRIM. They also noted that they have recently transitioned RRIM to an operating system that will allow PHMSA to make adjustments more frequently as data are collected and updated. However, officials further noted that these activities are in their initial stages, and that PHMSA has not yet developed tangible steps to assess RRIM.

Without a process that uses data to assess the effectiveness of RRIM, PHMSA is unable to demonstrate the validity of RRIM and whether it is effectively prioritizing pipelines for inspection. For example, *Standards for Internal Controls in the Federal Government* notes that activities such as comparing actual performance to planned or expected results and analyzing significant differences can help organizations achieve objectives.[67] In the context of RRIM, such an analysis could compare the characteristics of pipeline segments involved in recent incidents to pipeline segments assigned to each risk tier by RRIM. This analysis could

[65]OMB, *Management's Responsibility for Enterprise Risk Management and Internal Control*, OMB Circular No. A-123 (Washington, D.C.: Jul. 15, 2016).

[66]GAO-14-704G.

[67]GAO-14-704G.

provide a basis for PHMSA to assess the validity of the threat factors and weighting and to make adjustments over time that would improve RRIM. However, without a process that includes these types of activities, PHMSA lacks assurance that RRIM prioritizes inspections effectively and that its inspection approach maximizes safety benefits to the public.

Conclusions

While pipelines are a relatively safe mode of transporting inherently dangerous materials, an incident can pose a profound threat to life, property, and the environment. Though individual pipeline operators deploy a variety of materials and corrosion prevention technologies to guard against these threats, PHMSA has an important role in overseeing operator actions to ensure pipeline safety. Moreover, as PHMSA acknowledges, the size and diversity of the nation's 2.7-million mile pipeline network necessitates a risk-based approach to oversight. However, because PHMSA has not documented the basis for the design and key decisions of RRIM and has not formally evaluated its effectiveness at prioritizing pipelines for inspection, it is unclear how effectively the model has helped PHMSA manage its inspection resources or maximize safety benefits to the public. Federal management practices and principles identify the need to document decisions, to use the best available data and information to drive decisions, and to periodically assess key management activities. In the context of RRIM, these actions are complementary as documentation of its design could serve as a baseline for a data-driven evaluation of its effectiveness and a review of whether the assumptions and decisions made as part of the design are valid. Such an evaluation could complement the analytical projects planned by PHMSA's Office of Planning and Analytics to support a data-driven approach to PHMSA's oversight. Furthermore, these actions could help PHMSA refine and improve its proposal for more specific data collection through the National Pipeline Mapping System before PHMSA's current data collection authority expires in 2020 and help PHMSA make progress toward its goal of becoming a more data-driven and risk-based safety agency.

Recommendations for Executive Action

To assess and validate the effectiveness of PHMSA's RRIM in prioritizing pipelines for inspection, we recommend that the Secretary of Transportation direct the Administrator of PHMSA to take the following two actions:

- document the decisions and underlying assumptions for the design of RRIM, including what data and information were analyzed as part of determining each component of the model, such as the threat factors, weights, risk tiers, and inspection frequency.

- establish and implement a process that uses data to periodically review and assess the effectiveness of the model in prioritizing pipelines for inspection and document the results of these analyses.

Agency Comments

We provided the Department of Transportation and NTSB with a draft of this report for review and comment. In its comments, reproduced in appendix III, the Department of Transportation concurred with our recommendations. The Department of Transportation and NTSB also provided technical comments, which we incorporated as appropriate.

We are sending copies of this report to relevant congressional committees, the Secretary of Transportation, the Chair of NTSB, 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 IV.

Susan A. Fleming
Director, Physical Infrastructure Issues

Appendix I: Additional Observations on Pipeline Materials and Corrosion Prevention Technologies

The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 included a provision for GAO to consult with stakeholders to gather information on the range of pipeline materials used in the United States and other developed countries and the effectiveness of corrosion control techniques. This appendix provides perspectives obtained from interviews with a nongeneralizable sample of eight pipeline operators and eight additional stakeholders with expertise on pipeline materials and corrosion (expert stakeholders) on (1) the use of pipeline materials and corrosion prevention technologies internationally, and (2) the potential improvements in pipeline materials and corrosion prevention technologies.[1]

Operators and expert stakeholders we interviewed noted few differences between the types of pipeline materials and corrosion technologies used in the United States gas and hazardous liquid network compared to their counterparts in Canada and European Union countries. Specifically, a majority of operators and expert stakeholders stated that the use of steel, plastic, composites, and other materials in pipelines in the United States is very similar to their use in Canada and the European Union, though these expert stakeholders and operators noted some minor differences in the use of these materials.[2] For example, in comparison with the United States, three expert stakeholders noted that Canada may have wider use of higher grade steel—to provide strength for pipelines to operate at high operating pressures but with a thin pipeline wall—and one expert stakeholder said the European Union uses plastic and composites more widely in its network. A few of these expert stakeholders attributed these differences to less conservative design standards in Canada and the European Union than in the United States. Similarly, most of the operators and expert stakeholders we interviewed stated that similar corrosion prevention technologies used in the United States are commonly used throughout Canada and the European Union. For example, operators and expert stakeholders stated that coatings are

[1]For the purposes of this report, we refer to stakeholders with expertise on pipeline materials and corrosion as expert stakeholders. Because broad agreement existed across the operators and expert stakeholders for many of these topics and our sample was non-generalizable, we used indefinite quantifiers to describe the responses where appropriate, as defined in our methodology. See appendix II for more information.

[2]One of the 16 operators and expert stakeholders we interviewed stated that it did not know whether the use of these materials in the United States differed from their use in Canada, while 5 of the 16 operators and experts we interviewed said they did not know if there were differences between the United States and the European Union.

commonly used to prevent external corrosion in the United States, Canada, and the European Union, though two operators and expert stakeholders said European Union countries often make more widespread use of a three-layer polyethylene coating than is used in the United States.[3] In addition, two operators and expert stakeholders said the European Union's regulatory approach is more flexible at accommodating new technologies than the approach taken in the United States.

Operators and expert stakeholders were divided on the extent of future improvements in materials. For example, several operators and expert stakeholders stated that they anticipate pipeline operators will increase the use and development of higher grade steel. These operators and expert stakeholders noted these changes could include minor improvements in steel manufacturing to produce more widespread use of higher strength steel, but noted that pipelines manufactured with higher grade steels often have thinner walls and are less resistant to third-party damage. Additionally, a few operators and expert stakeholders stated that they anticipate further development of plastics and increased use of plastics across the pipeline network. For example, one expert stated that he expects the use of polyamide plastics, which are currently used in less than 1 percent of distribution pipelines, to be more widely used and at higher pressures in the future. In contrast, several operators and expert stakeholders stated that they anticipate few changes in pipeline materials in the next 10 years, noting that current materials (i.e., steel and plastic) are well known by the pipeline industry and have been successful in addressing corrosion challenges.

Similarly, operators and expert stakeholders had mixed opinions on whether there would be significant improvements in corrosion prevention technologies over the coming years. For example, several operators and expert stakeholders characterized coatings and cathodic protection as mature technologies and did not foresee significant further development in the next 10 years. In contrast, other operators and expert stakeholders stated that they expected that improvements in monitoring, data collection and analysis might help operators improve efforts to combat internal corrosion. For example, these operators and expert stakeholders anticipate greater use of automatic monitoring technology to provide

[3] A three-layer polyethylene coating is composed of a fusion-bonded coating, an intermediate layer of adhesive and outer layer of plastic.

continual information on pipeline conditions, and improved integration of cathodic protection data with other monitoring efforts. Operators and expert stakeholders also identified improved coating technology as a potential area for advancement, with one expert stakeholder noting that nanotechnology may be used to develop self-repairing coatings that do not require operators to excavate pipelines to repair.

Appendix II: Objectives, Scope and Methodology

The objectives of this report were to determine (1) the pipeline materials and corrosion prevention technologies that are used in the gas and hazardous liquid pipeline network and their respective benefits and limitations; (2) how selected pipeline operators train personnel to manage corrosion and the challenges that exist in ensuring personnel are qualified, and (3) how the Pipeline and Hazardous Materials Safety Administration (PHMSA) uses data on pipelines and corrosion prevention to inform its inspection priorities. In addition to the methodology described below, for each of these objectives, we reviewed pertinent PHMSA regulations, documents, and interviewed PHMSA headquarters officials. This report also includes information on the use of pipeline materials and corrosion prevention technologies outside the United States as well as potential future improvements in materials and corrosion prevention technologies, based on interviews with the selected operators and expert stakeholders. (See app. I.)

To determine what pipeline materials and corrosion prevention technologies are used to transport hazardous liquids and benefits and limitations, we analyzed the most recent full-year data (calendar years 2010–2015) on pipeline characteristics, including data on mileage, geography, materials transported, and pipeline materials and corrosion prevention technologies reported to PHMSA by pipeline operators. We also analyzed PHMSA data on the cause of pipeline incidents from 2010–2015. We did not review data prior to 2010 due to a significant change in PHMSA's reporting requirements in 2009 that PHMSA officials noted limits comparability of the data collected prior to that change. We did not review operator-reported data after 2015 because operator data from 2016 on pipeline characteristics was not expected to be finalized until June 2017, according to PHMSA. We assessed the data's reliability by reviewing PHMSA reports, analyzing the data to identify any outlier values, and interviewing PHMSA officials. We found the data to be sufficiently reliable for the purposes of answering this objective. We also reviewed Department of Transportation reports and academic literature on the benefits and limitations of various materials and corrosion prevention technologies.

We also interviewed a nongeneralizable sample of eight pipeline operators and eight additional stakeholders with expertise on pipeline materials and corrosion (expert stakeholders).[1] (See table 7.) These

[1]For the purposes of this report, we refer to stakeholders with expertise on pipeline materials and corrosion as expert stakeholders.

expert stakeholders represented entities including consultants, research organizations, and other organizations. To obtain a diverse set of viewpoints from pipeline operators, we selected operators based on descriptive data collected by PHMSA on an operator's pipeline network function (gathering, transmission, or distribution); the types of materials transported by the operator's network; the size (miles of pipeline) of an operator's pipeline network and the geographic dispersion; and recommendations from other stakeholders. We identified an initial pool of expert stakeholders by reviewing academic literature, prior GAO work, and trade publications, and based on recommendations made by officials we interviewed from the National Transportation Safety Board, staff from industry trade associations, and other industry stakeholders. We selected expert stakeholders based on their knowledge of pipeline materials and corrosion, as determined from a review of their professional qualifications and experience or position related to these topics, as well as recommendations of other stakeholders.[2] To verify their expertise, we obtained a curricula vitae, resume, or other biographical information, and confirmed their qualifications during the interview. We also asked pipeline operators and expert stakeholders for recommendations on other expert stakeholders during our interviews with them.

[2]For the purposes of our review, "professional qualifications" in this case generally means a professional engineer designation or Ph.D. in a relevant subject, such as engineering, chemistry, metallurgy, or similar. "Professional experience" in this case generally means extended employment in a relevant field, firms that provide pipeline materials and corrosion prevention services, maintenance or repair, quality control/quality assurance, research, or consulting. "Professional position" in this case generally means the attainment of a position that would indicate a high level of relevant experience or knowledge.

Table 7: Stakeholders with Specialized Expertise Selected for Interviews on Pipeline Materials and Corrosion

Stakeholder	Type of Stakeholder	Representatives Interviewed	Title
Colonial Pipeline	Pipeline Operator	Josh Stanley	Manager, Corrosion Prevention
Dominion Energy Ohio	Pipeline Operator	Vic Magazine Brian Moidel	Manager, Gas Operations Principal Engineer
Enbridge	Pipeline Operator	Len Krissa Len LeBlanc	Supervisor, Pipeline Integrity Engineering Corrosion Prevention Director, Pipeline Integrity Assessments/Reliability
NiSource	Pipeline Operator	Lee Reynolds	Manager of Gas Standards
Pacific Gas and Electric	Pipeline Operator	David McQuilling	Director of Corrosion Engineering and Services
Shell Pipeline	Pipeline Operator	Mike Courville Virgil Wallace	Operator Qualifications Coordinator Senior Integrity Engineer
Southern Star	Pipeline Operator	Randall Neff Randy Vandervort Brett Houtz	Manager, Corrosion Services Supervisor, Corrosion Services Senior Technical Specialist, Corrosion Services
Williams Companies	Pipeline Operator	Jared Ellsworth Justin Reynolds	Manager, Pipeline Safety Supervisor, Asset Integrity
Alberta Energy Regulator	Expert Stakeholder	Dave Grzyb	Technical Specialist, Pipeline Authorizations
DNV/GL	Expert Stakeholder	John Beavers	Corporate Vice President and Senior Principal Engineer
Dynamic Risk	Expert Stakeholder	Patrick Vieth	Senior Vice President of Technical Services
International Corrosion Services, Ltd.	Expert Stakeholder	Roger King	Director
Kiefner and Associates	Expert Stakeholder	Barry Hindin Michael Rosenfeld	Senior Principal Engineer Chief Engineer
MATCOR, Inc.	Expert Stakeholder	Jeff Didas	Senior Corrosion Engineer
Phil Hopkins, Ltd	Expert Stakeholder	Phil Hopkins	President and Pipeline Engineering Consultant
Pipeline Research Council International (PRCI)	Expert Stakeholder	Laurie Perry	Program Manager, Corrosion and Underground Storage

Source: GAO. | GAO-17-639

Our goal in talking to these operators and expert stakeholders was to collect a diverse set of perspectives on our questions and in doing so, there were operators and expert stakeholders we included because of their viewpoint to provide overall balance to the nonprobability, nongeneralizable sample. To mitigate any potential biases in our sample, we selected individuals with significant relevant experience or knowledge who represented a range of alternative perspectives. We assessed this criterion by reviewing the information used to confirm their qualifications and verifying that the individuals have the expertise to participate in our sample. Prior to conducting these interviews, we conducted two pretests to obtain feedback on the questions. We conducted a semi-structured interview with each operator and expert stakeholder and asked each stakeholder the same set of questions. Because broad agreement existed across the operators and expert stakeholders for many of these topics and our sample was non-generalizable, we used indefinite quantifiers to describe the responses. (See table 8.) The views provided by pipeline operators and these expert stakeholders cannot be generalized across all pipeline operators or expert stakeholders on these topics, but do provide perspectives on the benefits, limitations, factors affecting costs and other aspects of the pipeline materials and corrosion prevention technologies discussed by these stakeholders.[3] Furthermore, we did not attempt to identify all pipeline materials or all corrosion technologies. Rather, this information was obtained to provide a variety of perspectives on topics related to pipeline materials and corrosion and relevant to our objective.[4]

[3]While we collected information on benefits, limitations and factors affecting cost from these interviews, we did not review cost-benefit analyses or conduct a formal cost-benefit analysis due to a lack of available data. In addition, while we asked operators and expert stakeholders about the cost of materials and corrosion prevention technologies during our interviews with them, a majority of them stated that they could not provide specific estimates for materials and technologies, in part, because they depend on a variety of factors. As result, we reported on factors affecting the cost of these materials and technologies, rather than specific cost estimates.

[4]We also used this same approach to obtain perspectives on (1) the international use of materials and corrosion prevention technologies and (2) potential improvements in materials and corrosion prevention technologies, as detailed in appendix I.

Table 8: Indefinite Quantifiers Used to Describe Frequency of Operator and Expert Stakeholder Views on Pipeline Materials and Corrosion Prevention Technologies

Indefinite quantifier	Number of operators and expert stakeholders
A Few	2-4
Several	5-7
Half	8
Majority	9-12
Nearly all	13-15
All	**16**

Source: GAO. | GAO-17-639

To analyze how selected operators train personnel to manage corrosion and ensure that personnel were qualified, we reviewed PHMSA regulations and proposed changes to those regulations requiring that pipeline operator personnel are qualified for operational and maintenance tasks, including corrosion prevention activities. We reviewed pipeline operators' training plans and other documentation. We interviewed staff from 17 stakeholders: 8 pipeline operators, the same as selected above; 3 unions: the International Union of Operating Engineers, the Laborers' International Union of North America, and the Utility Workers Union of America; 3 training providers: the American Society of Mechanical Engineers, the National Association of Corrosion Engineers, and Veriforce; and 3 industry trade associations: the American Gas Association, the American Petroleum Institute, and the Interstate Natural Gas Association of America. These stakeholders were selected to provide a range of views on approaches, common practices, and challenges associated with corrosion training and operator qualification; however, these views are not generalizable across all industry stakeholders.

To determine how PHMSA uses data on pipelines and corrosion to inform its inspection priorities, we analyzed and assessed the reliability of the most recent PHMSA inspection and enforcement data (calendar years 2014–2016) on pipeline materials and corrosion prevention technologies. To assess the reliability of the data used for this objective, we reviewed PHMSA and Department of Transportation Office of Inspector General reports and PHMSA documentation, analyzed the data to identify any outlier values and interviewed PHMSA officials. We also reviewed the Oak Ridge National Laboratory's assessment of PHMSA's data management and analysis capabilities and challenges. We also interviewed PHMSA officials about how the data were collected, stored and validated. We determined that the data were sufficiently reliable for the purposes of addressing this objective. We evaluated PHMSA's use of this data in its risk-ranking index model as part of its effort to rank the relative risk of pipelines and prioritize its annual inspections of pipeline operators using these rankings. We compared this approach to criteria identified in *GAO's Standards for Internal Controls in the Federal Government*[5], criteria for risk analysis developed by the Office of Management and Budget (OMB),[6] and PHMSA's strategic objectives. In addition, we reviewed Department of Transportation reports on PHMSA's risk management models and approaches and interviewed former PHMSA officials about these topics. We also interviewed staff from each of PHMSA's five regional offices, which are responsible for conducting inspections of pipeline operator operations, and conducted a group interview of state officials from all nine interstate agents to understand how inspection data is collected and used to inform PHSMA's oversight.[7]

We conducted this performance audit from July 2016 to August 2017 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.

[5]GAO, *Standards for Internal Control in the Federal Government*, GAO-14-704G (Washington, D.C.: Sept. 10, 2014).

[6]OMB, *Updated Principles for Risk Analysis*, OMB-M-07-24 (Washington, D.C..: Sept, 19, 2007); *Management's Responsibility for Enterprise Risk Management and Internal Control*, OMB Circular No. A-123 (Washington, D.C.: July 15, 2016).

[7]Interstate agents are authorized by PHMSA to assist with the inspection of interstate pipelines. Of the nine states designated as interstate agents, four states (Connecticut, Michigan, Iowa, and Ohio) are designated solely as interstate agents for natural gas, one state (Virginia) is designated solely as an interstate agent for hazardous liquids, and four states (Arizona, Minnesota, New York and Washington) are designated for both.

Appendix III: Comments from the Department of Transportation

U.S. Department of Transportation

Office of the Secretary of Transportation

Assistant Secretary for Administration

1200 New Jersey Avenue, SE
Washington, DC 20590

Susan A. Fleming
Director, Physical Infrastructure Issues
U.S. Government Accountability Office
441 G Street NW
Washington, D.C. 20548

July 12, 2017

Dear Ms. Fleming:

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is committed to protecting people and the environment by advancing the safe transportation of energy and other hazardous materials that are essential to our daily lives. PHMSA utilizes a robust safety oversight framework that includes regulations, inspections, investigations, and enforcement activities to target the greatest risks facing pipeline systems, such as corrosion. PHMSA also collaborates and coordinates with Federal and State pipeline safety regulators, operator trade associations, emergency response organizations, public safety officials, and other stakeholders to help operators prevent, identify, assess, mitigate, and repair pipeline corrosion damage.

Finding better ways to reduce the number of corrosion-related incidents is a priority for PHMSA. PHMSA's recent activities in this area include the following:

- Creating inspection protocols focused on conditions and factors that can lead to the development of corrosion.
- Using a risk-ranking system to identify which pipeline systems should be prioritized for inspection.
- Promulgating regulations that identify requirements for pipeline materials, corrosion prevention, and operator qualification.
- Collaborating with NACE International (formerly known as the National Association of Corrosion Engineers) to share corrosion and pipeline safety information.
- Publishing multiple advisory bulletins to clarify regulations and inform/update operators regarding corrosion risks.
- Publishing guidance to clarify PHMSA's enforcement authority.

Upon review of the GAO's draft report, we concur with both recommendations. The Department will provide a detailed response to each recommendation within 60 days of the final report's issuance.

We appreciate the opportunity to respond to the GAO draft report. Please contact Madeline M. Chulumovich, Director of Audit Relations and Program Improvement, at (202) 366-6512 with any questions or if you would like to obtain additional details.

Sincerely,

Bryan Slater
Assistant Secretary for Administration

Appendix IV: GAO Contact and Staff Acknowledgments

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Staff Acknowledgments

In addition to the contact named above, Matt Barranca (Assistant Director), Matt Voit (Analyst in Charge), Katrina Ballard, David Blanding, Melissa Bodeau, David Hooper, Katrina Pekar-Carpenter, Adam Peterson, Malika Rice, Jim Russell, and Jack Wang made key contributions to this report.

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