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U.S. DOT Docket Management System  
Docket No. PHMSA-2011-0023  
U.S. Department of Transportation  
West Building Ground Floor  
Room W12-140  
1200 New Jersey Ave., SE  
Washington, DC 20590

RE:  Supplemental Comment of the American Petroleum Institute and GPA Midstream Association on “Pipeline Safety: Safety of Gas Gathering Pipelines,” RIN 2137-AF38

On December 21, 2018, the Pipeline and Hazardous Materials Safety Administration (PHMSA or Agency) released a presentation that the Agency intended to share with the Gas Pipeline Advisory Committee (GPAC)\(^1\) at a public meeting in Washington, D.C., which was originally scheduled for January 8-9, 2019.\(^2\) In the presentation, PHMSA described the gas gathering provisions in the “Safety of Gas Transmission and Gathering Pipelines” Notice of Proposed Rulemaking (NPRM),\(^3\) summarized the comments that the Agency received in response to the NPRM, and provided PHMSA’s recommendations to the GPAC for addressing those proposals in the next phase of the rulemaking process (GPAC Presentation). Shortly after releasing the presentation, PHMSA postponed the January 8-9, 2019 GPAC meeting due to an unanticipated lapse in funding.\(^4\)

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1. 49 U.S.C. § 60115(c) (2017). The GPAC is a 15-member peer review committee responsible for advising PHMSA “on the technical feasibility, reasonableness, cost-effectiveness, and practicability” of any proposed gas pipeline safety standard.
2. Copies of the materials are available on PHMSA’s website at https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=143
The American Petroleum Institute (API) and GPA Midstream Association (GPA) have carefully reviewed the GPAC Presentation, particularly the Agency’s recommendations for addressing the NPRM’s gas gathering proposals. While API and GPA support many of those recommendations, there are certain areas that require further comment. Accordingly, API and GPA are submitting this letter to PHMSA to highlight certain areas of concern prior to the GPAC meeting, which is now scheduled for June 25-26, 2019, in Washington, D.C.

I. Background

In April 2016, PHMSA proposed changes to the safety standards and reporting requirements for gas gathering lines in 49 C.F.R. Parts 191 and 192. The proposed changes included (1) repealing API Recommended Practice 80, “Guidelines for the Definition of Onshore Gas Gathering Lines,” 1st edition, April 2000, (API RP 80), the industry standard for defining onshore gas gathering operations that is incorporated into Part 192 by reference, and adopting new definitions by regulation; (2) applying certain safety standards to gas gathering lines in Class 1 locations that are 8 inches or greater in nominal diameter and which have a maximum allowable operating pressure (MAOP) that produces a hoop stress of 20 percent or more of specified minimum yield strength (SMYS) (for metallic lines) or is more than 125 PSIG (for non-metallic lines); (3) adding exceptions to the safety standards for currently-regulated Type A gathering lines to accommodate other proposed changes to the transmission line regulations; and (4) applying the reporting requirements in Part 191 to operators of all gathering lines, whether regulated or not.

In July 2016, API, GPA, and other industry stakeholders submitted comments responding to the NPRM. The industry commenters were generally opposed to PHMSA’s proposals, stating that the changes would adversely impact producers and gatherers by extending the Agency’s

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5 API is the national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and 8 percent of the U.S. economy. API’s more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation’s energy and are backed by a growing grassroots movement of more than 25 million Americans.

6 GPA has served the U.S. energy industry since 1921 and is composed of nearly 100 corporate members that are engaged in the gathering and processing of natural gas into merchantable pipeline gas, commonly referred to in the industry as “midstream activities.” Such processing includes the removal of impurities from the raw gas stream produced at the wellhead as well as the extraction for sale of natural gas liquid products (NGLs) such as ethane, propane, butane, and natural gasoline or in the manufacture, transportation, or further processing of liquid products from natural gas. GPA Midstream membership accounts for more than 90% of the NGLs produced in the United States from natural gas processing.

7 NPRM at 20,827-20,828. As the primary support for these proposals, PHMSA pointed to recent changes in the operating parameters of gas gathering lines in the nation’s shale plays, as well as concerns with the enforcement and application of API RP 80. Id. at 20,801-20,808. PHMSA also asserted that its proposals were consistent with a 2010 National Association of Pipeline Safety Representatives resolution and more recent U.S. Government Accountability Office recommendations relating to gas gathering lines. Id. at 20,808; PHMSA, Preliminary Regulatory Impact Assessment at 101 (Mar. 2016) (PRIA), https://www.regulations.gov/document?D=PHMSA-2011-0023-0117. See U.S. Gov’t Accountability Off., GAO-12-388, PIPELINE SAFETY: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety (Mar. 2012); U.S. Gov’t Accountability Off., GAO-14-667, OIL AND GAS TRANSPORTATION: Department of Transportation Is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety (Aug. 2014).

jurisdiction closer to the wellhead, requiring the widespread reclassification of pipeline facilities, and imposing unduly burdensome regulations and reporting requirements. The industry commenters further indicated that PHMSA’s Preliminary Regulatory Impact Assessment (PRIA) significantly underestimated the costs—and significantly overestimated the benefits—of the gas gathering proposals. While the PRIA estimated that the costs would exceed the benefits by approximately $1 million over the initial 15-year compliance period, an independent economic analysis submitted by API showed that the costs would exceed the benefits by more than $28 billion over that same period. API’s independent economic analysis further found that the NPRM would have a disproportionate economic impact on small operators, leading to annual compliance costs that would consume about 90% of the revenue generated by small gathering companies.

On December 4, 2018, API and GPA submitted a joint position paper to PHMSA on the NPRM’s gas gathering proposals in anticipation of the upcoming GPAC meeting. In the joint position paper, API and GPA reiterated that its members did not support the Agency’s proposal to repeal API RP 80 and adopt new gathering definitions. API and GPA noted that API RP 80 is a valid industry standard that enjoys broad support among producers and gatherers, and that API is in the process of developing a new edition of that standard. API and GPA also noted that the Agency’s proposed definitions lacked an adequate technical or legal foundation and would change the jurisdictional status of many facilities, imposing significant costs on the industry that PHMSA failed to consider in the PRIA. As for the Agency’s proposal to regulate Class I gas gathering lines, API and GPA expressed general support for the principle, but asked PHMSA to limit the regulations to higher-stress pipelines that are greater than 16 inches in nominal diameter. Pipelines with these operating characteristics, API and GPA observed, represent the new generation of large-diameter, high-pressure gas gathering lines that should be considered for further regulation.

API and GPA also expressed general support for applying the requirements for Type B gathering lines and emergency plans in § 192.615 to higher stress, Class I gas gathering lines greater than 16 inches in nominal diameter, so long as operators could deviate from those requirements by using the same variance provision that the Agency included in the new regulations for underground gas storage facilities. To make the requirements more efficient and cost effective, API and GPA urged PHMSA to consider incorporating other risk-based concepts into

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10 49 C.F.R. § 192.12(f). Section 192.12(f) allows operators of underground gas storage facilities to deviate from certain provisions in two industry standards incorporated by reference “when the operator includes or references written technical justifications in its program or procedural manual . . . as to why compliance with a provision of the recommended practice is not practicable and not necessary for safety with respect to specified underground storage facilities or equipment.” Id. To use the provision, “[t]he justifications for any deviation . . . must be technically reviewed and documented by a subject matter expert to ensure there will be no adverse impact on design, construction, operations, maintenance, integrity, emergency preparedness and response, and overall safety and must be dated and approved by a senior executive officer, vice president, or higher office with responsibility of the underground natural gas storage facility.” Id. Moreover, “[a]n operator must discontinue use of any variance where PHMSA determines and provides notice that the variance adversely impacts design, construction, operations, maintenance, integrity, emergency preparedness and response, or overall safety.” Id.
the Class 1 gas gathering line regulations as well.\textsuperscript{11} Finally, API and GPA expressed support for PHMSA’s proposal to apply the federal reporting requirements to Class 1 gas gathering lines, but only to a limited extent. Operators of regulated Class 1 gas gathering line, API and GPA agreed, should comply with the same reporting requirements as operators of other regulated gathering lines. Operators of unregulated Class 1 gas gathering lines should only be required to obtain an Operator Identification Number (OPID), file abbreviated annual reports, and submit incident reports for fatalities or injuries involving in-patient hospitalization.

On December 21, 2018, PHMSA released the GPAC Presentation, which included new recommendations for addressing the NPRM’s gas gathering proposals. The Agency recommended that the proposed changes to the gas gathering definitions be withdrawn,\textsuperscript{12} and that the minimum nominal diameter threshold for regulated Class 1 gas gathering lines be increased from 8 inches or greater to greater than 12 inches.\textsuperscript{13} The Agency also recommended that at least one dwelling be located within the PIR for Class 1 gas gathering lines at the lowest end of the nominal diameter threshold (greater than 12 inches and less than or equal to 16 inches) to be regulated.\textsuperscript{14}

As for the other proposals, PHMSA recommended that regulated Class 1 gathering lines be subject to the requirements for Type B gathering lines and the emergency response plan provisions in 49 C.F.R. § 192.615, that operators be given two years to achieve compliance, and that a “letter of no objection” provision be added to allow operators to use composite pipe in regulated systems. Lastly, the Agency recommended that operators of regulated Class 1 gas gathering lines comply with the same Part 191 reporting requirements as operators of other regulated gathering lines, that operators of unregulated Class 1 gas gathering lines comply with the incident and annual reporting requirements in Part 191, and that the annual reporting form for unregulated Class 1 gas gathering lines be modified to only require certain specific information.

\textsuperscript{11} In a separate letter submitted on December 4, 2018, GPA asked PHMSA to allow operators to exclude Class 1 gathering line segments that did not contain any buildings intended for human occupancy or identified sites within the potential impact radius (PIR). GPA, Supplemental Comments (Dec. 4, 2018), https://www.regulations.gov/document?D=PHMSA-2011-0023-0453 (included as an attachment). GPA explained that the addition of a PIR exception would be consistent with PHMSA’s integrity management (IM) regulations for gas transmission lines, PHMSA’s hazardous liquid pipeline safety regulations for rural gathering lines and low-stress lines, and the overarching risk-based philosophy of the pipeline safety regulations. GPA also noted that a PIR exception would ensure that PHMSA’s new regulations for Class 1 gas gathering lines satisfied the cost-benefit provision in the Pipeline Safety Act and were consistent with DOT policies, practices, and procedures and the President’s recent Executive Orders on regulatory reform, domestic energy independence, and economic growth.

\textsuperscript{12} The Agency noted that API was developing a new edition of API RP 80, and that PHMSA would monitor the results of that effort before considering any future changes to the gathering definitions. PHMSA, Safety of Gas Gathering Pipelines, GPAC Meeting at 80 (Jan. 8-9, 2018) (GPAC Presentation).

\textsuperscript{13} GPAC Presentation at 93. PHMSA said that the comments received in response to the NPRM indicated that a minimum nominal diameter threshold of greater than 12 inches would be sufficient to capture the larger diameter, higher pressure associated with unconventional shale gas production. Id. at 94.

\textsuperscript{14} API and GPA note that there is a discrepancy on slide 97, which recommends that the PIR limitation apply to Class 1 gathering lines greater than 12 inches \textit{through }16 inches \textit{in nominal diameter}, and that all Class 1 gathering lines greater than or \textit{equal to }16 inches \textit{in nominal diameter} be regulated without the PIR limitation. The discrepancy does not appear on slide 104, which appears to accurately reflect PHMSA’s recommendations.
II. Comments

The GPAC Presentation indicates that PHMSA is no longer interested in pursuing certain aspects of the NPRM, particularly the proposals to repeal API RP 80 and create new gas gathering definitions, to establish an 8-inch-minimum-nominal diameter threshold for regulated Class 1 gas gathering lines, and to apply the Part 191 reporting requirements to all Class 1 gathering lines, whether regulated or not. API and GPA welcome the Agency’s decision to abandon these previous proposals and adopt new positions, which will promote pipeline safety by making the new gathering line regulations more reasonable, efficient, and cost effective.

However, API and GPA remain concerned by some of the recommendations in the GPAC Presentation. API and GPA continue to believe that a variance provision should be added to the regulations, that the compliance deadlines should be staggered for certain activities to ensure orderly implementation and maintain consistency with previous rulemakings, and that regulated Class 1 gathering lines should be designated as Type C lines to avoid unnecessary complexity and confusion. In addition, GPA urges PHMSA separately to increase the maximum nominal diameter threshold for the PIR limitation from 16 inches to 24 inches, which will further focus the regulations for Class 1 gathering lines on the segments that present a higher risk to public safety.

To provide further clarity on these issues in advance of the GPAC meeting, API and GPA are providing the following supplemental comments on the GPAC Presentation.

a. API and GPA strongly support PHMSA’s recommendation to withdraw its proposal to repeal API RP 80 and establish new gas gathering definitions.

The GPAC Presentation indicates that the Agency intends to withdraw its proposed changes to the gas gathering definitions. API and GPA strongly support that recommendation for the reasons provided in the joint position paper and other comments submitted to PHMSA. API RP 80 is broadly supported by the industry, and the record does not support eliminating the use of that standard in determining the extent of onshore gas gathering operations. Moreover, the new definitions that PHMSA proposed do not comply with the rulemaking requirements in the Pipeline Safety Act and would change the jurisdictional status of many facilities, imposing significant costs that the Agency did not consider in the PRIA. API is also developing a new edition of API RP 80 and a separate industry standard, API Recommended Practice 1182 (API RP 1182), for the safety of rural gas gathering lines to address the concerns that the Agency identified in the NPRM. Accordingly, API and GPA strongly support PHMSA’s recommendation to retain the current definitions and monitor API’s progress and efforts to revise API RP 80 and develop API RP 1182 before making any changes to the regulations.

b. API and GPA generally support PHMSA’s recommendation to increase the minimum nominal diameter threshold for regulated Class 1 gas gathering lines from 8 inches or greater to greater than 12 inches.

The GPAC presentation indicates that PHMSA wants to increase the minimum nominal diameter threshold for regulated Class 1 gas gathering lines. While less than the threshold identified in the joint position paper (greater than 16 inches
in nominal diameter), API and GPA generally support the Agency’s recommendation. Increasing the minimum nominal diameter threshold to greater than 12 inches should exclude the smaller diameter gathering lines that serve conventional production facilities and focus PHMSA’s regulations on the new generation of large-diameter, high-pressure gas gathering lines that create additional risk to public safety, particularly when combined with the proposed PIR limitation. Furthermore, the record does not support the 8-inch nominal diameter threshold originally proposed in the NPRM. Conventional gas gathering systems throughout the United States are constructed with pipe ranging from 8 to 12 inches in nominal diameter, and there is no indication in the data currently available to suggest that these pipelines have a different risk profile than the rural gathering lines that have been exempt from regulation for decades. For these reasons, API and GPA generally support PHMSA’s recommendation to increase the minimum nominal diameter threshold for regulated Class 1 gas gathering lines from 8 inches or greater to greater than 12 inches.

c. API and GPA support PHMSA’s recommendation to add a PIR limitation to the Class 1 gas gathering line regulations.

The GPAC presentation indicates that the Agency wants to add a PIR limitation to the regulations for Class 1 gathering lines at the lower end of the minimum nominal diameter threshold (greater than 12 inches through 16 inches). API and GPA support the recommendation to include a PIR limitation, which will help to further focus the regulations on gathering lines that present a higher risk to public safety. The PIR concept is well-established in PHMSA’s IM regulations, and gathering lines that do not have any dwellings within the PIR pose little or no risk to public safety. Although API has not reached consensus support on the issue, GPA urges PHMSA to expand the PIR limitation to pipelines up to 24 inches in nominal diameter. GPA believes the Agency has not provided a sound technical basis for restricting the PIR limitation to pipelines that are 16 inches or less in nominal diameter. The PIR of a 24-inch pipeline with an MAOP of 1440 psig does not exceed the standard width of a class location unit (220 yards, or 660 feet),\(^{15}\) and operators are already collecting information about the presence of dwellings in class location units in conducting class location studies. Applying the PIR limitation to pipelines up to 24 inches in nominal diameter would not impose any additional costs on operators, and the regulations would be far more efficient and cost effective.

d. API and GPA generally support PHMSA’s recommendation to apply the requirements for Type B gathering lines and emergency plans to regulated Class 1 gas gathering lines.

The GPAC Presentation indicates that the Agency wants to apply the requirements for Type B gathering lines and the emergency response plan provisions in § 192.615 to regulated Class 1 gas gathering lines. API and GPA generally support that recommendation for the reasons provided in the joint position paper. Gathering line operators are familiar with the Type B regulations, and industry understands the importance of applying emergency response requirements to larger diameter, higher pressure pipelines in Class 1 locations.

\(^{15}\) 49 C.F.R. § 192.5(a)(1).
e. *API and GPA agree that appropriate steps must be taken to accommodate the use of composite pipe materials in regulated systems, but have concerns about PHMSA’s recommendation to add a “letter of no objection” process for regulated Class 1 gathering lines.*

The GPAC Presentation indicates that the Agency wants to add a “letter of no objection” provision to the Class 1 gathering line regulations for composite pipe materials. Although API and GPA agree that appropriate steps must be taken to accommodate the use of composite pipe materials in regulated systems, its members believe the Agency should outline how the process would work in practice, including the standards that PHMSA would follow in issuing letters of no objection and the remedies that would be available to an operator for seeking further review in the event of an unfavorable result. The Agency should also provide further clarification about its decision to limit the “letter of no objection” process only to the use of composite pipe materials. PHMSA’s regulations have not applied to Class 1 gas gathering lines for decades due to a longstanding historical exemption, and operators are likely to experience compliance challenges in other areas. The Agency needs to provide operators with a reasonable means for navigating such a dramatic change in jurisdictional status, and experience has shown that the special permit process is not a workable alternative.

f. *API and GPA continue to believe that a variance provision should be included in the Class 1 gas gathering regulations.*

The GPAC Presentation indicates that the Agency is opposed to adding a variance provision to the Class 1 gas gathering line regulations. API and GPA do not support that recommendation for the reasons provided in the joint position paper. PHMSA included a variance provision in the regulations for underground gas storage facilities, and the same flexibility should be afforded to operators of newly-regulated Class 1 gas gathering lines. A variance provision will allow operators of pipelines constructed with composite materials to perform repairs or replacements without pursuing the unduly burdensome special permit process. Operators could also use the variance provision where necessary to ensure that Class 1 gas gathering lines are designed, constructed, operated, and maintained in accordance with the latest industry safety standards and practices. As in the underground gas storage regulations, the justification for a deviation would need to be reviewed by an appropriate subject matter expert and approved by a responsible company official. Operators would also need to maintain appropriate supporting documentation, and PHMSA would have the authority to direct an operator to discontinue using a variance where necessary to ensure pipeline safety.

g. *API and GPA continue to believe that a staggered set of 2-year, 3-year, and 5-year compliance deadlines should apply to regulated Class 1 gas gathering lines.*

The GPAC Presentation indicates that the Agency is proposing a 2-year deadline for regulated Class 1 gas gathering line operators to achieve compliance. API and GPA do not support that recommendation, which is more stringent than the deadlines that PHMSA imposed in establishing the current gathering line regulations. The Agency originally provided staggered deadlines over a 3-year period for achieving compliance with the requirements for regulated

10 See note 10, supra.
gathering lines, i.e., October 15, 2007, for damage prevention and MAOP establishment; April 15, 2008, for line markers and public awareness; and April 15, 2009, for corrosion control. The proposed regulations for Class 1 gathering lines would affect more operators and mileage, and PHMSA has not offered any justification for using a shorter, 2-year compliance deadline in this proceeding. API and GPA propose a 2-year initial compliance deadline for damage prevention, public awareness, line marker, and emergency response requirements and establishing MAOP. A 3-year initial compliance deadline should be provided for the leak detection and repair requirements, and a 5-year compliance deadline should be provided for the corrosion control requirements.

h. API and GPA strongly support PHMSA’s recommendations to add exceptions to Part 192 so that regulated gathering line operators are not subject to certain transmission line requirements.

The GPAC Presentation indicates that the Agency wants to add exceptions to Part 192 so that regulated gathering line operators are not subject to certain transmission line requirements. Specifically, the GPAC Presentation states that exceptions for gas gathering lines will be provided from the following new transmission line requirements in the MAOP and IM mandates rule: 49 C.F.R. §§ 192.150 (requiring new lines designed and constructed to accommodate inline inspection devices to meet NACE), 192.227(c) (records for qualification of welders), 192.285(e) (records for qualification of plastic pipe joiners), 192.493 (In-Line Inspection (ILI) consensus standards), 192.506 (spike hydrotesting), 192.607 (materials documentation), 192.619(e) (MAOP confirmation), 192.624 (MAOP confirmation), 192.710 (non-HCA assessments), and 192.712 (Analysis of Predicted Failure Pressure). The GPAC Presentation also states that exceptions for gas gathering lines will be provided from the following new transmission line requirements in the gas transmission line repair rule: 49 C.F.R. §§ 192.13(d) (management of change), 192.127 (pipe design records), 192.205 (records for pipeline components), 192.319 (coating surveys after backfill), 192.461(f) (coating surveys after backfill), 192.465(d)(2) & (f) (external corrosion remediation), 192.473(c) (interference surveys), 192.478 (internal corrosion), 192.613(c) (extreme weather inspection), and 192.714 (non-HCA repair criteria). API and GPA strongly support adding these exceptions in Part 192.

i. API and GPA continue to believe that regulated Class 1 gas gathering lines should be designated as Type C lines.

While not directly addressed in the GPAC Presentation, API and GPA continue to believe that regulated Class 1 gas gathering lines should be designated as Type C lines. PHMSA’s proposal to use the “Type A, Area 2” designation for regulated Class 1 gathering lines is confusing and introduces unnecessary complexity into the Type A and Type risk framework currently used in Part 192. Using the Type C designation for regulated Class 1 gathering lines is consistent with that framework and provides operators with greater clarity on the applicability of the pipeline safety rules.

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17 49 C.F.R. § 192.9(e).
18 GPAC Presentation at 117.
19 Id. at 118.
API and GPA generally support PHMSA’s recommendation for applying the Part 191 reporting requirements to Class 1 gathering lines.

The GPAC Presentation indicates that the Agency wants operators of regulated Class 1 gas gathering lines to comply with the same reporting requirements as operators of other regulated gathering lines. PHMSA also wants operators of unregulated Class 1 gas gathering lines to comply with the incident reporting requirements and submit a streamlined version of the annual reporting form. API and GPA are generally supportive of these recommendations, but would prefer that the incident reporting requirements for unregulated Class 1 gas gathering lines be limited to injuries requiring in-patient hospitalization or fatalities.

III. Conclusion

API and GPA share PHMSA’s commitment to pipeline safety and appreciate the opportunity to submit these supplemental comments on the proposed changes to the federal safety standards and reporting requirements for gas gathering pipelines. Please feel free to contact us directly if you have any additional questions or concerns.

Sincerely,

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Attachments (3)
JOINT POSITION PAPER
submitted by the
AMERICAN PETROLEUM INSTITUTE
and
GPA MIDSTREAM ASSOCIATION
on
“Pipeline Safety: Safety of Gas Gathering Pipelines,” RIN 2137-AF38

Notice of Proposed Rulemaking Published by the Pipeline and Hazardous Materials Safety Administration,
U.S. DEPARTMENT OF TRANSPORTATION,

Submitted December 4, 2018

I. Introduction

The American Petroleum Institute (API)\(^1\) and GPA Midstream Association (GPA)\(^2\) appreciate the opportunity to submit this joint position paper on the Pipeline and Hazardous Material Safety Administration’s (PHMSA) proposed changes to the federal safety standards and reporting requirements for gas gathering pipelines.\(^3\) PHMSA proposed those changes in an April 8, 2016 notice of proposed rulemaking (NPRM),\(^4\) and the Gas Pipeline Advisory Committee (GPAC) will

\(^1\) API is the national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and 8 percent of the U.S. economy. API’s more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation’s energy and are backed by a growing grassroots movement of more than 25 million Americans.

\(^2\) GPA has served the U.S. energy industry since 1921 and is composed of nearly 100 corporate members that are engaged in the gathering and processing of natural gas into merchantable pipeline gas, commonly referred to in the industry as “midstream activities.” Such processing includes the removal of impurities from the raw gas stream produced at the wellhead as well as the extraction for sale of natural gas liquid products (NGLs) such as ethane, propane, butane, and natural gasoline or in the manufacture, transportation, or further processing of liquid products from natural gas. GPA Midstream membership accounts for more than 90% of the NGLs produced in the United States from natural gas processing.


\(^4\) On March 24, 2018, PHMSA advised the Gas Pipeline Advisory Committee that the notice of proposed rulemaking would be separated into three separate final rules for the remainder of the rulemaking process, and that one of those final rules would be dedicated exclusively to gas gathering lines.
be meeting on January 8 to 9, 2019, at the U.S. Department of Transportation’s (DOT) headquarters in Washington, D.C., to consider the NPRM’s gas gathering provisions. The GPAC is a 15-member peer review committee responsible for advising PHMSA “on the technical feasibility, reasonableness, cost-effectiveness, and practicability” of any proposed gas pipeline safety standard. PHMSA is required to provide the GPAC with a risk assessment and other supporting information as part of the rulemaking process.

In anticipation of the GPAC meeting, PHMSA asked API and GPA to submit a joint position paper on the NPRM’s gas gathering proposals. API and GPA represent a significant portion of the producers and gatherers that will be affected by this rulemaking proceeding, and our members welcome the opportunity to assist PHMSA in preparing the materials that will be presented to the GPAC.

II. Executive Summary

- **Gas Gathering Definitions.** API and GPA do not support PHMSA’s proposal to adopt new definitions for determining if a pipeline is an onshore gas gathering line. The current regulations, which largely incorporate the functional approach established in API Recommended Practice 80, “Guidelines for the Definition of Onshore Gas Gathering Lines,” 1st edition, April 2000, (API RP 80), allow operators to accommodate the wide variety of production and gathering operations that occur throughout the United States. PHMSA’s proposed definitions are not necessary, would impose an undue burden on producers and gatherers, and do not have adequate technical or legal support. Accordingly, API and GPA urge PHMSA to retain API RP 80 and the definitions in the current regulations without modification.

- **Class 1 Gas Gathering Lines.** API and GPA support PHMSA’s proposal to adopt new safety standards for Class 1 gas gathering lines, but only for pipelines that (1) are greater than 16 inches in nominal outside diameter and (2) have a maximum allowable operating pressure (MAOP) that produces a hoop stress of 20 percent or more of specified minimum yield strength (SMYS) for metallic lines or is more than 125 PSIG for non-metallic lines. Pipelines with these operating characteristics represent the new generation of large-diameter, high-pressure gas gathering lines that PHMSA did not foresee in adopting the current risk-based regulations. API and GPA generally support PHMSA’s proposal to apply the requirements for Type B gathering lines and emergency plans to regulated Class 1 gas gathering lines, so long as operators can deviate from those requirements if a variance with written technical justification is included in appropriate program documentation. PHMSA should also consider whether other risk-based concepts can be used to reduce or minimize the burden imposed by any new regulations on Class 1 gas gathering lines that meet the nominal outside diameter criteria (greater than 16 inches) and MAOP thresholds.

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6 Id. § 60115(c).
7 API and GPA both previously submitted detailed comments on the NPRM’s gas gathering provisions. The joint positions reflected in this paper are generally consistent with those comments, except with respect certain clarifications and modifications. API and GPA expect that PHMSA will consider the information provided in their respective comments and this joint position paper in addressing any changes to the current regulations for onshore gas gathering lines.
Gas Gathering Reporting Requirements. API and GPA support PHMSA’s proposal to apply the federal reporting requirements to Class 1 gas gathering lines, but only to a limited extent. Regulated Class 1 gas gathering line operators should only be required to obtain an Operator Identification Number (OPID), file abbreviated annual reports, and submit incident reports. Operators of unregulated Class 1 gas gathering lines should be required to obtain an OPID, file abbreviated annual reports, and submit incident reports for fatalities or injuries involving in-patient hospitalization.

III. Background

In the Natural Gas Pipeline Safety Act of 1968 (1968 Act), the U.S. Congress provided DOT with the authority to prescribe minimum federal safety standards for the transportation of gas by pipeline. The 1968 Act defined “transportation of gas” to include “the gathering, transmission, distribution of gas by pipeline or its storage in or affecting interstate or foreign commerce[,]” but specifically excluded “the gathering of gas in those rural locations which lie outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, a community development, or any similar populated area which the Secretary may define as a nonrural area[.]” The legislative history indicates that Congress decided to exclude rural gas gathering lines from DOT’s jurisdiction, because the industry’s “impressive” safety record did not support the need for federal regulation.

In 1970, DOT established the original minimum federal safety standards for gas pipeline facilities in 49 C.F.R. Part 192. Consistent with the statutory prohibition in the 1968 Act, the original DOT regulations “did not apply the gathering of gas outside of . . . any area within the limits of any incorporated or unincorporated city, town, or village” or “[a]ny designated residential or commercial area such as a subdivision, business or shopping center, or community development.” However, gas gathering lines within these populated areas were subject to the requirements that applied to transmission lines. The original DOT regulations also provided a general definition for the term “gathering line”. That general definition, which is still codified
in the current regulations, provides that a gathering line is “a pipeline that transports gas from a current production facility to a transmission line or main.”

More than two decades later, Congress amended the federal pipeline safety laws to provide DOT with additional authority to regulate rural gas gathering lines. Specifically, the Pipeline Safety Act of 1992 (1992 Act) directed DOT to create a new regulatory definition for the term “gathering line” within two years after considering the “functional and operational characteristics” of gas gathering lines and without regard to any classification used by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act. The 1992 Act also directed DOT to issue regulations within three years establishing minimum federal safety standards for a subset of so-called “regulated gathering line[s].” In deciding on “the types of the lines which are functionally gathering but which, due to specific physical characteristics, warrant regulation[,]” the 1992 Act required DOT to “consider such factors as location, length of line from the well site, operating pressure, throughput, and the composition of the transported gas.”

In 1999, API launched an effort to create a new recommended practice for defining onshore gas gathering operations. That effort, led by an industry coalition representing nearly two dozen oil and gas and pipeline trade organizations, culminated with the publication of API RP 80 in April 2000. To accommodate the wide variety of operations that occur throughout the United States, the coalition that drafted API RP 80 used two core principles to differentiate between production and gathering operations: (1) function and (2) the furthermost downstream concept. The coalition considered and rejected several other factors in adopting these core principles, including physical parameters (size, length, operating pressure), gas quality, gas throughput, custody transfer, geopolitical boundaries, and other regulatory designations.

In March 2006, PHMSA concluded a lengthy rulemaking process by adopting the current regulations for onshore gas gathering lines. Those regulations require operators to follow API RP 80 in determining if a pipeline meets the definition of an “onshore gathering line,” subject to certain additional limitations to prevent. The regulations apply two categories of onshore gas gathering lines: (1) Type A gathering lines, which include metallic lines with an MAOP of 20

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15 Id.; 49 C.F.R. § 192.3 (2017). In 1974, DOT initiated a rulemaking proceeding that sought to clarify the original gathering line definition. Transportation of Natural and Other Gas by Pipeline; Definition of a Gathering Line, 39 Fed. Reg. 34,569, 34,570 (Sept. 26, 1974). DOT terminated that proceeding four years later without changing the definition in response to strong opposition to the proposal. Transportation of Natural and Other Gas by Pipeline; Definition of a Gathering Line, 43 Fed. Reg. 42,773 (Sept. 21, 1978).
17 Id.
18 Id.
19 Id. Four years later, in the Accountable Pipeline Safety and Partnership Act of 1996 (1996 Act), Congress further amended the federal pipeline safety laws to provide DOT with the authority to “require owners and operators of gathering lines to provide the Secretary information pertinent to the Secretary’s ability to make a determination as to whether and to what extent to regulate gathering lines.” Pub. L. No. 104-304, § 12, 110 Stat. 3793, 3802 (codified at 49 U.S.C. § 60117(b)).
21 49 C.F.R. § 192.8(a).
percent or more of SMYS, as well as nonmetallic lines with an MAOP of more than 125 PSIG, in a Class 2, 3, or 4 location; and (2) Type B gathering lines, which include metallic lines with an MAOP of less than 20 percent of SMYS, as well as nonmetallic lines with an MAOP of 125 PSIG or less, in a Class 2 location (as determined under one of three formulas) or in a Class 3 or Class 4 location. Operators of Type A and Type B lines must comply with certain gas transmission line regulations and the federal reporting requirements, except for the National Pipeline Mapping System (NPMS) provisions. PHMSA’s pipeline safety standards and reporting requirements do not currently apply to Class 1 gas gathering lines.

In April 2016, PHMSA published an NPRM proposing extensive changes to the regulations for gas gathering lines. Specifically, PHMSA proposed to (1) repeal API RP 80 and adopt a series of new definitions for determining whether a pipeline is an onshore gas gathering line; (2) apply certain pipeline safety standards to Class 1 gas gathering lines; (3) modify the safety standards that apply to Type A gathering lines; and (4) apply the reporting requirements to operators of all gathering lines, whether regulated or not. As the primary support for these proposals, PHMSA pointed to recent changes in the operating parameters of gas gathering lines in the nation’s shale plays, as well as concerns with the enforcement and application of API RP 80. PHMSA also asserted that its proposals were consistent with a 2010 National Association of Pipeline Safety Representatives (NAPSR) resolution and more recent U.S. Government Accountability Office (GAO) recommendations relating to gas gathering lines.

API, GPA, and other industry stakeholders submitted comments responding to the NPRM’s gas gathering provisions. The industry commenters generally indicated that PHMSA’s proposals would undermine the risk-based structure of the current regulations and have a significant adverse impact on producers and gatherers by extending PHMSA jurisdiction closer to the wellhead, requiring the widespread reclassification of pipeline facilities, and imposing unduly burdensome regulations and reporting requirements. The industry commenters also indicated that PHMSA’s Preliminary Regulatory Impact Analysis (PRIA) significantly underestimated the costs—and significantly overestimated the benefits—of the gas gathering proposals. While the PRIA estimated that the costs would exceed the benefits by approximately $1 million over the initial 15-year compliance period, an independent economic analysis submitted by API showed that the costs would exceed the benefits by more than $28 billion over that same period. API’s independent economic analysis further found that the NPRM would have a disproportionate economic impact on small operators, leading to annual compliance costs that would consume about 90% of the revenue generated by small gathering companies.

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22 Id. 192.8(b) (table)
23 Id.
24 NPRM at 20,827-20,828.
25 Id. at 20,801-20,808.
IV. Joint Position on Gas Gathering Proposals

A. Gas Gathering Definitions

Current Rules: Operators use API RP 80 to determine if a pipeline is an onshore gas gathering line, subject to certain additional regulatory limitations.

PHMSA Proposal: Repeal API RP 80 and add new definitions for determining whether a pipeline is an onshore gas gathering line.

API-GPA Position: Retain API RP 80 and make no other changes to the definitions in the current regulations.

1. Current Rules

Operators are currently required to use API RP 80 to determine the extent of production and gathering operations, subject to certain additional regulatory limitations. API RP 80 defines a production operation as “piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids[.]” A production operation also includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply[.] as well as “individual well flowlines, equipment piping, transfer lines between production operation equipment elements and sites, and tie-in lines to connect to gathering, transmission, or distribution lines.” Part 192 prohibits certain dual-use equipment from being classified as part of a production

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27 49 C.F.R. § 192.8(a).
28 API RP 80 § 2.3. PHMSA does not have the authority to regulate production facilities or operations. See 49 U.S.C. § 60101(a)(21)(A); 49 C.F.R. §§ 192.8 and 192.9; Letter from Cesar DeLeon, Dir., Regulatory Programs Office of Pipeline Safety to Mr. Edward M. Steele, Supervisor, Gas Pipeline Safety Section, The Public Utilities Comm’n of Ohio at 1, PHMSA PI-92-010 (Mar. 12, 1992) (“Part 192 does not apply to production facilities”); Letter from Cesar DeLeon, Dir., Regulatory Programs Office of Pipeline Safety to Mr. Lance Fellhoalter, engineering Technician, OXY USA, Inc. at 1, PHMSA PI-93-060 (Oct. 8, 1993) (“The regulations in Parts 40, 191, 192, and 199 apply to pipeline facilities used in the transportation of gas beginning at the end of the production process.”).
29 API RP 80 § 2.3. Section 2.4 of API RP 80 provides a list of supplemental definitions for the terms used in defining a “production operation.” The terms covered in Section 2.4 include: (1) “Extraction and recovery,” which is defined as “operations used to move liquid and/or gas products from their resident place in the underground reservoir to the surface and separate them into their individual components.” (2) “Separation,” which is defined as “[t]he physical and/or chemical technique used to segregate produced well fluids (oil, water, gas), e.g., separator vessels, heater treaters, emulsion treaters, free water knockouts, chemelectric units, etc.” (3) “Treatment,” which is defined as “[t]he physical and/or chemical technique used to enhance separation of produced well fluids and removal of impurities (e.g., water, solids, basic sediment and water, sulfur compounds, carbon dioxide, etc.).” (4) “Stabilization,” which is defined as “[t]he treatment of produced fluids during which some gas may evolve” and where “[t]he gas is removed to make liquid product(s) less volatile.” (5) “Production compression,” which is defined as “[c]ompression situated within the production field and used to (A) enhance production through reduced backpressure on the wells, gas lift, and/or gas injection, and/or (B) boost produced gas pressure to enhance delivery into a gas gathering line.”
30 API RP 80 § 2.4.4(a).
operation. Specifically, “equipment that can be used in either production or transportation, such as separators or dehydrators” is not part of a production operation “unless that equipment is involved in the processes of ‘production and preparation for transportation or delivery of hydrocarbon gas’ within the meaning of ‘production operation.’”  

API RP 80 defines an onshore gas gathering line as “any pipeline or part of a connected series of pipelines” that “transport[s] gas from the furthest downstream point in a production operation to the furthest downstream” point in one of the following five locations:

- **Gas Processing Plant.** “[T]he inlet of the furthest downstream natural gas processing plant, other than a natural gas processing plant located on a transmission line.”
- **Gas Treatment Facility.** “[T]he outlet of the furthest downstream gathering line gas treatment facility.”
- **Point of Commingling.** “[T]he furthest downstream point where gas produced in the same production field or separate production fields is commingled.”
- **Compressor Station.** “[T]he outlet of the furthest downstream compressor station used to lower gathering line operating pressure to facilitate deliveries into the pipeline from production operations or to increase gathering line pressure for delivery to another pipeline.”
- **Incidental Gathering.** “[T]he connection to another pipeline downstream of” these endpoints or the furthest production operation.

Fuel gas return lines are also classified as gathering lines under API RP 80.

PHMSA has imposed three additional regulatory limitations on API RP 80’s definition of a gathering line to prevent misapplication of the furthest downstream concept:

- **Gas Processing Plant.** “The endpoint of gathering . . . may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.”

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31 49 C.F.R. § 192.8(a)(1).
32 *Id.* PHMSA has said that this restriction for dual-use equipment “is intended to establish the end of production operations and the beginning of gathering operations at the point where gas transitions to single phase flow regardless of whether or not the gas meets the gas quality requirements of the transmission line.” PHMSA, Onshore Gas Gathering FAQs at 16b, [https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/about-phmsa/grants/pipeline/57056/gathering-faqs-7112007.pdf](https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/about-phmsa/grants/pipeline/57056/gathering-faqs-7112007.pdf) (last visited Nov. 27, 2018).
33 API RP 80 § 2.2(a)(1) (emphasis added). Note that a gathering line “may have intermediate deliveries (to other production operations, pipeline facilities, farm taps, or residential/commercial/industrial end users) that are not necessarily part of the gathering line.” *Id.* Also note that natural gas processing plants are excluded from API RP 80’s gathering line definition. *Id.* § 2.2(b).
34 API RP 80 states that a pipeline is a gathering line if it is “transport[ing] gas from a point other than in a production operation exclusively to points in or adjacent to one or more production operations or gathering facility sites for use as fuel, gas lift, or gas injection gas within those operations[.]” API RP 80 § 2.2(a)(2).
35 49 C.F.R. § 192.8(a)(2)-(4).
36 *Id.* § 192.8(a)(2) (emphasis added).
In adopting this limitation, PHMSA stated “many of our prior interpretations have based the end of gathering on the first downstream processing plant.”  

- **Point of Commingling.** “If the endpoint of gathering . . . is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case.”

- **Compressor Station.** “The endpoint of gathering . . . may not extend beyond the furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline.”

Incidental gathering is a recognized designation under the current rules. PHMSA considers ‘incidental gathering’ to include only lines that directly connect a transmission line to one of the [other] endpoints . . . [in section 2.2(a)(1) of API RP 80], as limited by [49 C.F.R. § 192.8]. Lines that connect a transmission line to one of these endpoints by way of another facility are not considered ‘incidental gathering.’

2. **PHMSA’s Proposal**

In the NPRM, PHMSA proposed to repeal API RP 80 and establish new definitions for determining whether a pipeline qualifies as an onshore gas gathering line. Two new terms and definitions would primarily be used for that purpose: (1) “Onshore production facility or onshore production operation” and (2) “Gathering line (Onshore)”.

Supplemental definitions for “Gas processing plant” and “Gas treatment facility” would also play a role in determining the endpoint of gathering operations. While not acknowledged in the NPRM or considered in the PRIA, PHMSA’s proposed definitions are not consistent with API RP 80 and would change the classification of many pipeline facilities from production to gathering, or from gathering to transmission or distribution.

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38 49 C.F.R. § 192.8(a)(3).
39 Id. § 192.8(a)(4).
40 Letter to Mr. Greg Schrab, CDX Gas, PHMSA PI-09-0002 at 2 (Jul. 14, 2009) (stating that “incidental gathering [line] designations are currently permissible due to [a] drafting error”) (CDX Gas Interpretation); Letter to Mr. Leo M. Haynos, Kansas Corp. Comm’n, PHMSA PI-09-0008 at 4 (Jul. 30, 2009) (stating that “incidental gathering designations are currently permissible due to [a] drafting error”) (KCC Interpretation). Contrary to the statements made in these letters of interpretation, API and GPA do not agree that PHMSA’s decision to recognize the incidental gathering designation is the product of a drafting error. The rulemaking history clearly shows that PHMSA intended to allow operators to use the incidental gathering provisions in API RP 80. Gas Gathering Line Definition 71 Fed. Reg. at 13,292.
42 NPRM at 20,801–20,809.
43 NPRM at 20,825–826.
44 Id. at 20,825. PHMSA’s proposal required operators of existing pipeline systems to establish the beginning and endpoints of each gathering line using these new definitions within six months and maintain records documenting the results of that evaluation. Id. at 20,827. Operators of new gathering lines would be required to make the same determination before the line is placed into service and to maintain records documenting the results of that evaluation. Id. As API and GPA indicated in their respective comments, the six-month deadline proposed in the NPRM for reclassifying all existing gas gathering lines is unreasonable even if PHMSA had an adequate legal basis for adopting the new definitions. Comments of API at 49-51 (July 7, 2016); Comments of GPA Midstream at 21-22 (July 7, 2016)
In providing a justification for the new definitions, PHMSA stated in the NPRM that the current rules are “difficult for operators to apply consistently to complex gathering system configurations[,]” and that “[e]nforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system[.]” PHMSA also stated that it had “identified a regulatory gap that permits the potential misapplication of [API RP 80’s] incidental gathering line designation . . .” PHMSA stated that the agency and NAPSR had voiced some of these concerns about API RP 80 before adopting the current regulations, and that PHMSA advised pipeline operators in recent letters of interpretation of its desire to clarify the application of the incidental gathering line designation.

3. API-GPA Position

API and GPA do not support PHMSA’s proposal to repeal API RP 80 and establish new definitions for determining the extent of production and gathering operations. Like other federal agencies, PHMSA is generally required “to use voluntary consensus standards and design specifications developed by voluntary consensus standard bodies instead of government-developed voluntary technical standards when applicable.” A broad coalition of interested parties developed API RP 80 using the same American National Standards Institute procedures that apply in developing all other API standards. API reaffirmed API RP 80 in 2013 and is in the process of developing a new edition of the standard. API RP 80 satisfies all relevant procedural and legal requirements to remain incorporated in PHMSA’s regulations.

Contrary to PHMSA’s statements in the NPRM, operators have not experienced any difficulty in applying API RP 80. API RP 80 is designed to accommodate the wide variety of oil and gas operations that occur throughout the United States, and the emphasis on function and use of the furthestmost downstream concept provides operators with the flexibility necessary to distinguish between production and gathering operations in complex configurations. Numerous industry commenters expressed their continued support for API RP 80 in this proceeding, and many of those stakeholders are participating in API’s ongoing effort to develop a new edition of that standard.

PHMSA’s criticism of API RP 80 as conflicting, ambiguous, or overly complex is misplaced. The integrity management (IM) regulations for gas transmission lines contain more than two dozen sub-sections, incorporate the provisions in another industry standard by reference, and cross-reference a separate guidance document. The IM regulations are far more complex and challenging to apply than API RP 80. There is also no support for PHMSA’s claim that API RP 80 cannot be effectively enforced. The NPRM and PRIA do not identify any proceedings that substantiate PHMSA’s alleged difficulties in enforcing the current rules, and the record does not

45 NPRM at 20,801.
46 Id. at 20,807.
47 Id. at 20,803, 20,807.
49 49 C.F.R. Part 192, Subpart O.
indicate that the state authorities generally responsible for regulating production and gathering operations are failing to ensure public safety.\(^{50}\)

The use of the incidental gathering line designation is neither a misapplication of API RP 80 nor inconsistent with the current rules. API RP 80 appropriately recognizes that incidental gathering lines are a continuation of the gathering process, and PHMSA acknowledged that the current regulations permit the use of that designation in the March 2006 final rule.\(^{51}\) Any concerns about the regulatory status of incidental gathering lines can be addressed by applying appropriate safety standards to large-diameter, high-pressure gathering pipelines in Class 1 locations.

PHMSA’s proposed definitions do not satisfy the rulemaking requirements in the Pipeline Safety Act.\(^{52}\) In prescribing a new definition for the term “gathering line,” the statute requires PHMSA to “consider functional and operational characteristics of the lines to be included in the definition.”\(^{53}\) PHMSA must also consider certain generally-applicable factors in establishing any new pipeline safety standard, including the available relevant gas pipeline safety information, the reasonableness, appropriateness, and reasonably identifiable or estimated costs and benefits of a proposed standard, and the comments and information received from the public.\(^{54}\) There is no indication in the NPRM or PRIA that PHMSA even considered these statutory requirements in developing the proposed gathering definitions.

Nor do the proposed definitions meet the Pipeline Safety Act’s cost-benefit provision. PHMSA assumed in the PRIA that the NPRM’s gathering definitions are consistent with the current rules and would impose no additional cost on the midstream industry.\(^{55}\) The text of the current regulations, and the comments submitted in this proceeding, directly contradict that assumption. PHMSA’s proposed definitions would end the production function at a point much closer to the wellhead than API RP 80.\(^{56}\) PHMSA’s proposed definitions would also impose restrictions on the use of the incidental gathering line classification that are not recognized in API RP 80 or the current rules, requiring operators to reclassify many gathering lines as transmission or distribution lines.\(^{57}\) PHMSA did not consider the significant economic impact that these changes would have on producers and gatherers in the PRIA.

\(^{50}\) In fact, many of the safety standards administered by state authorities that do not have a certification to participate in the pipeline safety program would be preempted if PHMSA adopts the definitions proposed in the NPRM. 49 U.S.C. § 60104(c); Olympic Pipeline Co. v. City of Seattle, 437 F.3d 872 (9th Cir. 2006).


\(^{52}\) 49 U.S.C. §§ 60101(b); 60102(b)(2).


\(^{54}\) 49 U.S.C. § 60102(b)(2).

\(^{55}\) PRIA at 100.

\(^{56}\) The NPRM would end production operations at the point where “[m]easurement for the purposes of calculating minerals severance occurs; or there is commingling of the flow stream from two or more wells[,]” whichever is furthermost downstream. NPRM at 20,826. API RP 80 recognizes that “[t]he production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation.” API RP 80 § 2.3.1.1.

For these reasons, API and GPA do not support PHMSA’s proposal to repeal API RP 80 and establish new definitions for determining the extent of production and gathering operations. The current regulations allow operators to effectively classify the wide variety of operations that occur throughout the United States, and the record does not provide an adequate legal or technical basis for adopting the changes proposed in the NPRM. Accordingly, PHMSA should retain API RP 80 and the current regulations without further modification.

B. Class 1 Gas Gathering Lines

**Current Rules:** PHMSA’s regulations only apply to regulated onshore gas gathering lines (Type A and Type B) in Class 2, 3, or 4 locations. Gas gathering lines in Class 1 locations are not regulated.

**PHMSA Proposal:** Regulate Class 1 gas gathering lines that are 8 inches or more in nominal outside diameter with an MAOP that produces a hoop stress of 20 percent or more of SMYS (metallic lines) or is more than 125 PSIG (non-metallic lines) as Type A, Area 2 lines. Operators of Type A, Area 2 lines must comply with the regulations for Type B gathering lines and implement emergency plans.

**API-GPA Position:** Regulate Class 1 gas gathering lines that are greater than 16 inches in nominal outside diameter with an MAOP that either produces a hoop stress of 20 percent or more of SMYS (metallic lines) or is more than 125 PSIG (non-metallic lines) as Type C lines. Operators of Type C lines should comply with the regulations for Type B gathering lines and implement emergency plans, unless a variance with written technical justification is included in appropriate documentation. Consider whether other risk-based concepts can be used to reduce or minimize the burden imposed by any new regulations.

1. **Current Rules**

If a pipeline meets the definition of an onshore gas gathering line, the regulations require an operator to determine if the line qualifies as a regulated onshore gathering line. Part 192 currently recognizes two categories of regulated onshore gathering lines:

- **Type A Gathering Lines.** Type A gathering lines are defined by regulation to include metallic lines with an MAOP of 20 percent or more of SMYS, as well as nonmetallic lines with an MAOP of more than 125 PSIG, in a Class 2, 3, or 4 location. Operators of Type A lines must comply with all of the requirements for transmission lines, except for the provisions that require accommodation of smart pigs in new and replaced lines.

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58 49 C.F.R. § 192.8(b) (table).
59 Id.
and the gas IM requirements; they are also permitted to use an alternative process for complying with the operator qualification requirements.60

- **Type B Gathering Lines.** Type B gathering lines are defined by regulation to include metallic lines with an MAOP of less than 20 percent of SMYS, as well as nonmetallic lines with an MAOP of 125 PSIG or less, in a Class 2 location (as determined under one of three formulas) or in a Class 3 or Class 4 location.61 Operators of any new or substantially changed Type B line must comply with the design, installation, construction, and initial testing and inspection requirements for transmission lines and, if the line is of metallic construction, the corrosion control requirements for transmission lines.62 Operators must include Type B lines in their damage prevention and public education programs; establish the MAOP of these lines under § 192.619; comply with the line marker requirements for transmission lines; and conduct leak surveys and promptly repair hazardous leaks.63

PHMSA’s regulations do not currently apply to gas gathering lines in Class 1 locations. A Class 1 location is “an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline . . . that has 10 or fewer buildings intended for human occupancy.”64

2. **PHMSA’s Proposal**

In the NPRM, PHMSA proposed to regulate certain gas gathering lines in Class 1 locations.65 Specifically, PHMSA proposed to regulate Class 1 gas gathering lines that (1) are 8 inches or greater in nominal outside diameter and (2) have an MAOP of 20 percent or more of SMYS for metallic lines or more than 125 PSIG for non-metallic pipe.66 Operators of these lines, which are designated as Type A, Area 2 gathering lines in the NPRM, would need to comply with the requirements that currently apply to Type B regulated gathering lines (damage prevention program, corrosion control (for metallic piping), public awareness and education program, MAOP, line marker, and leak surveys), as well as the emergency response plan requirements in Part 192.67

The proposal in the NRPM gives operators 6 months to determine if existing gathering lines meet the new Type A, Area 2 criteria and document the results of that evaluation.68 Operators of existing Type A, Area 2 lines would need to achieve compliance with the proposed safety standards within 2 years (unless an operator is able to justify otherwise and obtain PHMSA approval).69 Operators of newly installed Type A, Area 2 lines, or existing lines that are replaced, relocated, or otherwise

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60 Id. § 192.9(c).
61 Id. § 192.8(b) (table).
62 Id. § 192.9(d)(1) and (2).
63 Id. § 192.9(d)(3)-(7).
64 49 C.F.R. § 192.5(a)(1) - (b)(1).
65 NPRM at 20,827-20,828.
66 Id. at 20,827.
67 Id. at 20,827-20,828.
68 Id. at 20,827.
69 Id. at 20,828.
changed, would also need to comply with the design, construction, and testing requirements in Part 192.  

In justifying these proposed changes, PHMSA pointed to recent developments in the field of natural gas exploration and production. PHMSA said in the NPRM that operators are constructing shale gas gathering lines that far exceed historical operating parameters, particularly from a pressure and diameter perspective. PHMSA said that the agency did not foresee or consider the risks associated with these kinds of gathering line systems in developing the March 2006 final rule, and that recent GAO recommendations provide further support for the proposed regulations. PHMSA also noted in the PRIA that the outside diameter and MAOP criteria used to delineate Type A, Area 2 gathering lines are consistent with a 2010 resolution passed by NAPSR.

The PRIA estimated that the average annual costs of these proposed changes ($12.8M to $15.3M) would exceed the average annual benefits ($11.3 to $14.2M) over the initial 15-year compliance period. Rather than using actual data on the current safety record of Class 1 gas gathering lines, which PHMSA has not collected, the PRIA made a series of assumptions about the potential impact of the proposed rules in arriving at these estimates. For example, the PRIA used data provided in the 2006 rulemaking and the current proceeding to estimate the mileage affected and compliance costs of the proposed rules. The PRIA also relied on data for transmission lines in Class 1 and 2 locations to estimate the benefits.

3. **API-GPA Position**

API and GPA support PHMSA’s proposal to regulate gas gathering lines in Class 1 locations, but only if the nominal outside diameter threshold is to pipe that is greater than 16 inches. Other than citing to a 2010 NAPSR resolution and a 2014 GAO recommendation concerning pipeline emergency response planning, PHMSA offers no technical support for the 8-inch nominal outside diameter threshold proposed in the NPRM. Conventional gas gathering systems throughout the United States are constructed with pipe ranging from 8 to 16 inches in nominal outside diameter, and there is no data in the record to suggest that these pipelines have a different risk profile than the rural gathering lines that have been exempt from regulation for nearly five decades.

The ongoing effort to develop a new API recommended practice for rural gas gathering lines shows that the new generation of higher risk gas gathering lines in the nation’s shale plays are greater than 16 inches in nominal outside diameter. API, GPA, and other interested stakeholders have been working for the past year to develop a recommended practice that complements PHMSA’s...
current regulations and desire to establish new safety standards for Class 1 gas gathering lines. In response to input provided throughout that process, API recently decided to limit the scope of the new recommended practice to pipelines that are greater than 16 inches in nominal outside diameter. API determined that there is a consensus on the need to establish a risk-based recommended practice for these large diameter rural gathering lines. A consensus does not exist on the need or approach that should be used in establishing a more uniform set of safety practices for smaller diameter gas gathering lines in rural areas.

API and GPA support PHMSA’s proposed MAOP criteria for Class 1 gas gathering lines. The MAOP thresholds in the NPRM are currently used to distinguish between Type A and Type B gathering lines. The 20 percent or more of SMYS limitation is also one of the criteria used in determining whether a pipeline is a gas transmission line. So long as PHMSA recognizes that the operating profile of gas gathering systems changes over time, particularly with the rapid production decline curves that occur during the initial phase of a shale play’s development, the proposed MAOP thresholds can serve as a useful indicator of potential risk.

Consistent with the comparable requirements for hazardous liquid pipelines, PHMSA should allow Class 1 gas gathering operators to use the MAOP limitation for non-metallic pipe (more than 125 PSIG) if any variable necessary to determine the stress level of metallic pipe is unknown. PHMSA allows operators to use that MAOP threshold if the stress level of steel pipe is unknown in determining whether a rural gathering line is regulated under 49 C.F.R. § 195.11. Allowing Class 1 gas gathering line operators to use the same limitation as an alternative to the design regulations for steel pipe is more efficient and avoids a conflict with the Pipeline Safety Act’s non-retroactivity provision.

API and GPA generally support PHMSA’s proposal to apply the requirements for Type B gathering lines and emergency plans to regulated Class 1 gathering lines, provided operators can deviate from those requirements if a variance with written technical justification is approved in appropriate program documentation. PHMSA included a similar variance provision in the new regulations for underground gas storage facilities, and operators of newly-regulated Class 1 gas gathering lines should be afforded the same flexibility. Such a provision will allow operators of pipelines constructed with materials not approved for use under PHMSA’s regulations to perform repairs or replacements without pursuing the unduly burdensome special permit process. Operators could also use a variance to ensure that Class 1 gas gathering lines are designed, constructed, operated, and maintained in accordance with the latest safety standards and practices.

API and GPA ask PHMSA to consider whether other risk-based concepts can be included in the new regulations to reduce or minimize the burden imposed on operators of Class 1 gas gathering lines that are greater than 16 inches in nominal outside and satisfy the MAOP thresholds described in the previous paragraphs. For example, PHMSA’s hazardous liquid pipeline safety regulations use proximity to unusually sensitive areas as a measure of potential environmental impact in determining the regulatory status of rural gathering lines and low-stress lines. The gas IM

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78 49 C.F.R. § 192.8(b)(2)(table).
79 Id. § 192.3 (definition of transmission line).
80 Id. § 192.12(f).
81 Id. §§ 195.11(a)(2), 195.12(b).
regulations use a pipeline’s potential impact radius, and the presence of identified sites or a certain number of buildings intended for human occupancy within the potential impact circle, in determining if a transmission line segment is in a high consequence area.\textsuperscript{82} Whether these or other concepts are considered, the critical point for API and GPA is that the new regulations allow operators to effectively and efficiently allocate resources in managing the risks associated with Class 1 gas gathering pipelines that are greater than 16 inches in nominal outside diameter and satisfy the aforementioned MAOP thresholds.

API and GPA urge PHMSA to refer to newly-regulated Class 1 gas gathering lines as “Type C” lines. The NPRM designates these lines as Type A, Area 2 lines, a reference that introduces unnecessary complexity and confusion into the regulations. Using the Type C designation for regulated Class 1 gathering lines is consistent with the current risk framework and provides operators with greater clarity on the applicability of those provisions.

API and GPA also urge PHMSA to clarify the specific gas transmission line regulations that apply to regulated Class 1 gas gathering lines to address certain discrepancies and inconsistencies in the NPRM. Note that for simplicity the list below refers to Type A, Area 1 lines as Type A lines, and Type A, Area 2 lines as Type C lines.

- \textit{Corrosion Control Requirements}. The NPRM included certain exceptions from the corrosion control requirements for Type A lines but did not provide the same exceptions for Type B lines or Type C lines.\textsuperscript{83} As a result, the corrosion control requirements for higher-risk Type A lines are less stringent than the requirements for lower-risk Type B lines and Type C lines. PHMSA needs to address that disparity by aligning the list of exceptions to the corrosion control requirements for all regulated gathering lines in the final rule.

- \textit{MAOP Requirements}. Under the NPRM, operators of Type C lines and Type B lines must establish MAOP in accordance with 49 C.F.R. § 192.619.\textsuperscript{84} However, PHMSA is proposing to amend § 192.619 in another part of the NPRM by adding a new subsection (e) to the regulation.\textsuperscript{85} As currently proposed, § 192.619(e) requires operators of certain gas transmission lines to comply with an elaborate set of MAOP verification requirements in 49 C.F.R. § 192.624.\textsuperscript{86} The assumptions laid out in the NPRM and PRIA and congressional mandate that prompted PHMSA to issue § 192.624 confirm that the proposed MAOP verification requirements are only applicable to gas transmission lines, not gas gathering lines. PHMSA affirmed that position in discussing the gas transmission line proposals before the GPAC. To avoid any uncertainty, PHMSA needs to clearly state in the final rule that operators of Type B lines and Type C lines only need to comply with 49 C.F.R. §192.619(a)-(d) in establishing MAOP.

\textsuperscript{82} \textit{Id.} §§ 192.901-905.
\textsuperscript{83} NPRM at 20,828.
\textsuperscript{84} \textit{Id.}
\textsuperscript{85} \textit{Id.} at 20,833.
\textsuperscript{86} \textit{Id.}
Compliance Deadline. The NPRM provides a 2-year deadline from the effective date of the final rule for operators of Type C lines to achieve compliance, unless the PHMSA Administrator finds that a later deadline is justified in a particular case. By way of comparison, the March 2006 final rule provided a series of staggered deadlines over a 3-year period for achieving compliance with the requirements for regulated gathering lines, i.e., October 15, 2007, for damage prevention and MAOP establishment; April 15, 2008, for line markers and public awareness; and April 15, 2009, for corrosion control. The rules proposed in the NPRM affect more pipeline operators and mileage, and PHMSA does not offer any justification in the NPRM or PRIA for providing a shorter compliance deadline in this proceeding. Operators of existing Type C lines need additional time to achieve compliance with the proposed rules. A 2-year initial compliance deadline should be provided for the damage prevention, public awareness, line marker, and emergency response requirements and establishing MAOP. A determination as to whether a pipeline qualifies as a Type C line will necessarily need to be made as part of those efforts. A 3-year initial compliance deadline should be provided for the leak detection and repair requirements. A 5-year compliance deadline should be provided for the corrosion control requirements.

Class Location Changes. PHMSA should clarify the regulations proposed in the NPRM that would apply to gathering lines that become regulated due to changes in class location or an increase in dwelling density. The Pipeline Safety Act prohibits PHMSA from retroactively applying design, construction, initial inspection, or initial testing requirements to pipelines in existence at the time when those requirements were adopted. The non-retroactivity provision applies to existing gathering lines that become regulated due to changes in class location or an increase in dwelling density. Accordingly, the proposed regulation in section 192.9(f) should be amended to clearly state that none of the design, installation, construction, initial inspection, and initial testing requirements in Part 192 apply to those lines.

PHMSA is proposing to amend the existing regulation that lists the safety standards that apply to higher stress, onshore gas gathering lines in Class 2, 3, or 4 locations. These gathering lines, currently designated as Type A lines, are subject to the requirements for gas transmission lines, except for the IM requirements in Subpart O and the provisions relating to the accommodation of inline inspection tools. PHMSA is proposing to expand that list of exceptions to accommodate many of the new proposals offered in the NPRM that would otherwise apply to gas transmission line operators.

Two of the most significant proposals in the NPRM are not on the amended list of exceptions for Type A lines: (1) the proposed regulation (49 C.F.R. § 192.607) for verifying pipeline materials where reliable, traceable, verifiable, and complete records are lacking, and (2) the proposed regulations (49 C.F.R. §§ 192.619(e), 192.624) for verifying MAOP through the use of pressure

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87 Id. at 20,828.
88 49 C.F.R. § 192.9(e).
89 NPRM at 20,828.
90 Id.
91 49 C.F.R. § 192.9(c).
testing, pressure reductions, engineering critical assessments, alternative technologies, or pipeline
replacements. The congressional mandate in Section 23 of the Pipeline Safety Act of 2011\(^2\) and
assumptions laid out in the NPRM and PRIA make clear that these proposals may only be applied
to gas transmission lines. There is no other basis in the record for requiring operators of Type A
lines to comply with these requirements. Accordingly, the proposed pipeline materials and MAOP
verification regulations (49 C.F.R. §§ 192.607, 192.619(e), 192.624) must be added to the list of
exceptions from the transmission line requirements for operators of Type A lines.

Consistent with the joint positions described above, API and GPA suggest that PHMSA adopt the
following regulatory language in the final rule:

\[\text{§ 192.8(c) How are gathering lines and regulated onshore gathering lines determined?}\]

<table>
<thead>
<tr>
<th>Type</th>
<th>Feature</th>
<th>Area</th>
<th>Safety buffer</th>
</tr>
</thead>
</table>
| A | — Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part  
— Non-metallic and the MAOP is more than 125 PSIG (862 kPa) | Class 2, 3, or 4 location (see §192.5) | None. |
| B | — Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part.  
— Non-metallic and the MAOP is 125 PSIG (862 kPa) or less. | Area 1. Class 3 or 4 location  
Area 2. An area within a Class 2 location the operator determines by using any of the following three methods:  
(a) A Class 2 location.  
(b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings; or  
If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster

(c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings of dwellings in Area 2(b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.

| C | —Metallic pipe greater than 16 inches in nominal outside diameter and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must either determine the stress level according to the applicable provisions in subpart C of this part, or use the MAOP limitation for non-metallic pipe. | Class 1 location | None |
|   | —Non-metallic pipe greater than 16 inches in nominal outside diameter and the MAOP is more than 125 PSIG (862 kPa) |   |   |

§ 192.9 What requirements apply to gathering lines?

* * * * *

(c) *Type A lines.* An operator of a Type A, Area 1 regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d)-(e), 192.150, and 192.319(d), 192.461(a)(4) and (f), 192.465(f), 192.473(e), 192.478, 192.485(e), 192.493, 192.506, 192.607 (including any references in other requirements), 192.619(e) (including any references in other requirements), 192.624 (including any references in other requirements), 192.631, 192.710, 192.711, 192.713, and in subpart O of this part. However, an operator of a Type A, Area 1 regulated onshore
(d) *Type B lines.* An operator of a Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines, except the requirements in §§192.13(d)-(e), 192.150, and 192.319(d), 192.506, any references to §§192.607, 192.619(e), or 192.624, and 192.631;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines, except the requirements in §§192.461(a)(4) and (f), 192.465(f), 192.473(c), 192.478, 192.485(c), and 192.493;

* * * * *

(5) Establish the MAOP of the line under §192.619(a)-(d), except for any references to §§192.607 or 192.624;

* * * * *

(e) *Type C lines.* Except as provided in paragraph (3) of this subsection, an operator of a Type C regulated onshore gathering line must:

(1) Comply with the requirements in subsection (d) of this section for Type B lines; and

(2) Implement an emergency plan in accordance with §192.615, except for the requirements in §192.615(a)(3).

(3) An operator may deviate from the requirements in paragraphs (1)-(2) of this subsection if a variance with written technical justification is included in appropriate program documentation. A subject matter expert must conduct a review to ensure that the design, construction, testing, operation, maintenance, integrity, and overall safety of the affected pipeline facility will not be adversely impacted by the variance. The subject matter expert must provide the results of that review to a senior executive officer, vice president, or higher officer in writing for approval. A variance cannot be used if the Associate Administrator notifies the operator that the variance adversely impacts the design, construction, operations, maintenance, integrity, or overall safety of the affected pipeline facility.
(f) If a regulated onshore gathering line existing on [effective date of the final rule] was not previously subject to this part, an operator has until:

(1) [date two years after effective date of the final rule] to comply with the applicable requirements of this section for the damage prevention, public education, MAOP, line markers, and emergency plans;

(2) [date three years after effective date of the final rule] to comply with the applicable requirements for leak detection and repair; and

(3) [date five years after effective date of the final rule] to comply with the applicable requirements for corrosion control and any other provisions applicable to Type A lines

unless the Administrator finds a later deadline is justified in a particular case.

(f) If, after [effective date of the final rule], a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has one year for Type B lines and Type C lines and two years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section. Nothing in this subsection requires an operator to comply with the design, installation, construction, initial inspection, or initial testing requirements in this part.

C. Reporting Requirements for Class 1 Gas Gathering Lines

Current Rules: PHMSA’s reporting requirements only apply to Type A lines and Type B lines.

PHMSA Proposal: Whether regulated or not, operators of all Class 1 gas gathering lines must obtain an OPID and comply with PHMSA’s incident, safety-related condition, and annual reporting requirements.

API-GPA Position: Type C gathering line operators should obtain an OPID, file abbreviated annual reports, and submit incident reports. Operators of unregulated Class 1 gas gathering lines should obtain an OPID, file abbreviated annual reports, and submit incident reports (only for deaths or injuries involving in-patient hospitalization).

1. Current Rules

Operators of Type A and Type B gathering lines must comply with PHMSA’s federal reporting requirements, including the provisions for providing immediate notification of certain incidents, submitting annual reports, reporting safety-related conditions, and obtaining an OPID.93 By

93 49 C.F.R. Part 191.
statute, Type A and Type B gathering line operators are not required to submit geospatial data to the NPMS.\textsuperscript{94} Class 1 gas gathering lines are not currently subject to any of the federal reporting requirements.\textsuperscript{95}

2. **PHMSA’s Proposal**

The NPRM proposed to apply PHMSA’s reporting requirements to all Class 1 gas gathering line operators (whether regulated or not), except for the obligation to submit data to the NPMS. Specifically, the NPRM would require Class 1 gas gathering operators to submit incident reports, safety-related condition reports, reports for MAOP exceedances, and annual reports. The NPRM also proposed to require all Class 1 gas gathering line operators to submit information to the National Operator Registry.

3. **API-GPA Position**

API and GPA support PHMSA’s proposal to apply the federal reporting requirements to Class 1 gas gathering lines, but only to a limited extent. Type C gathering line operators should be required to obtain an OPID, file abbreviated annual reports, and submit incident reports. Operators of unregulated Class 1 gas gathering lines should be required to obtain an OPID, file abbreviated annual reports, and submit incident reports for fatalities or injuries involving in-patient hospitalization.

Although the Pipeline Safety Act provides PHMSA with the authority to collect “information pertinent to [PHMSA’s] ability to make a determination as to whether and to what extent to regulate gathering lines,” the proposal to indiscriminately extend all of the reporting requirements to Class 1 gas gathering line operators fails to meet that standard.\textsuperscript{96} The NPRM and PRIA do not explain why operators must provide all of the data sought in PHMSA’s reports for the agency to make a reasoned determination on the need for future regulation. As described in more detail below, PHMSA can obtain sufficient data on the safety of Class 1 gas gathering lines through the submission of incident and annual reports.

- **Incident Reports.** PHMSA proposed in the NPRM to apply the incident reporting requirements to operators of all Class 1 gas gathering lines, whether regulated or not.\textsuperscript{97} API and GPA agree that operators of Type C lines should be subject to the same incident reporting requirements as regulated Type A and Type B lines. However, API and GPA do not agree that operators of unregulated Class 1 gas gathering lines should be required to report all incidents. Operators of unregulated gathering lines should be required to report incidents resulting in a death or injury necessitating in-patient hospitalization, which clearly have a direct impact on public safety. The other events that trigger the incident reporting requirements (estimated property damage of $50,000 or more, unintentional estimated gas loss of three million cubic feet or more, or an event that is significant in the judgment of the operator) do not always have that same direct impact. Requiring

\textsuperscript{94} 49 U.S.C. § 60132(a) (providing an exception for gathering and distribution lines); 49 C.F.R. § 191.29.
\textsuperscript{95} 49 C.F.R. § 191.1(b)(4).
\textsuperscript{96} 49 U.S.C. § 60117(b).
\textsuperscript{97} NPRM at 20,824-20,825.
unregulated gathering line operators to report those incidents would impose an undue burden on the industry.

- **Annual Reports.** The NPRM proposed to apply the annual reporting requirement to all Class 1 gathering lines. API and GPA agree that operators of Type C lines should be subject to the same annual reporting requirements as regulated Type A and Type B lines. API and GPA also agree that unregulated Class 1 gas gathering line operators should be required to submit annual reports. However, Class 1 gas gathering line operators should not be required to provide the same information in annual reports as operators of transmission and distribution lines. PHMSA should develop an abbreviated annual report form for gas gathering lines, and that form should only ask operators to submit information that is readily available directly relevant to gas gathering operations. PHMSA’s regulations have not applied to gas gathering lines in Class 1 location for the past five decades, and operators of these systems may not have the same detailed records as operators of traditionally regulated transmission and distribution systems. While that information will become more readily over time, PHMSA should carefully limit the data that Class 1 gas gathering line operators need to provide in annual reports, particularly during this initial phase of regulation. Information that would be appropriate for the abbreviated annual reporting form includes gathering line mileage by state, outside diameter, class location, Type (A, B, C, Unregulated), material, and decade of installation. Operators should be allowed to respond with unknown if information is not available.

- **Safety-Related Conditions, Including MAOP Exceedances.** The NPRM proposed to apply the requirement for reporting of safety-related conditions, including MAOP exceedances, to unregulated gathering lines. PHMSA clarified in a series of webinars held immediately prior to the end of the comment period and during the GPAC’s review of the NPRM’s gas transmission line proposals that the agency did not intend to apply these reporting requirements to operators of unregulated gathering lines. API and GPA support that clarification and are offering text to that effect for PHMSA to consider adopting in the final rule.

- **OPID Requirements.** The NPRM proposed to apply all of the requirements in the National Registry of Pipeline and LNG operators to Class 1 gas gathering lines, including the provisions for OPID requests and reporting certain changes to PHMSA within 60-day windows. API and GPA agree that operators of Type C lines should be subject to the same requirements as regulated Type A and Type B lines. However, operators of unregulated Class 1 gas gathering lines should only be required to obtain an OPID, which is necessary for administrative purposes in filing incident and annual reports. They should not be required to report the other changes that trigger the 60-day notifications to PHMSA.

Consistent with the foregoing joint positions, API and GPA suggest that PHMSA adopt the following changes to Part 191 in the final rule:

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98 Id.
99 Id.
100 Id.
§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-related conditions, exceedances of maximum allowable operating pressure (MAOP), annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of gas pipeline facilities located in the United States or Puerto Rico, including pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) * * *

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9;

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator; or

(4) Onshore gathering of gas—

(i) Through a pipeline that operates at less than 0 psig (0 kPa);

(ii) Through an onshore pipeline that is not a regulated onshore gathering line (as determined in § 192.8 of this chapter), except for reporting an incident that results in a death or personal injury involving in-patient hospitalization in accordance with §§ 191.3, 191.5, and 191.15, the report submission requirements in § 191.7(a) and (d), the annual reporting requirements for gas gathering pipeline systems in § 191.17, and the OPID requirements in § 191.22(a) and (d); and

(iii) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612.
V. Conclusion

API and GPA share PHMSA’s commitment to pipeline safety and appreciate the opportunity to submit this joint position paper on the proposed changes to the federal safety standards and reporting requirements for gas gathering pipelines. Please feel free to contact us directly if you have any additional questions or concerns.

Sincerely,

David Murk
Pipeline Manager, Midstream
American Petroleum Institute
1220 L Street, NW 900
Washington, DC 20005

Matthew Hite
Vice President of Government Affairs
GPA Midstream Association
On December 4, 2018, the American Petroleum Institute (API) and GPA Midstream Association (GPA) submitted a joint position paper on the Pipeline and Hazardous Material Safety Administration’s (PHMSA) proposed changes to the federal safety standards and reporting requirements for gas gathering pipelines. Please be advised that the proposed regulatory text for 49 C.F.R. § 192.9(c) on page 19 contained a typographical error.

Consistent with the joint industry comments submitted previously submitted on June 6, 2018, the proposed regulatory text should read as follows:

§ 192.9 What requirements apply to gathering lines?

* * * * *

(c) Type A lines. An operator of a Type A, Area 1 regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, [except the requirements in §§ 192.5(d), 192.13, 192.67, 192.127, 192.150, 192.205, 192.227(c), 192.285(e), 192.319, 192.461(f), 192.465(f)-(g), 192.473(c), 192.475(b)].
192.478, 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e)-(f), 192.624, 192.710, 192.711, 192.712, 192.713, 192.714, 192.750, and in subpart O of this part. However, an operator of a Type A, Area 1 regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

Sincerely,

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Matthew Hite
Vice President of Government Affairs
GPA Midstream Association
December 4, 2018

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Washington, DC 20590-0001


I. Introduction

On December 4, 2018, the GPA Midstream Association (GPA Midstream)\(^1\) and the American Petroleum Institute (API) submitted a joint position paper to the Pipeline and Hazardous Materials Safety Administration (PHMSA) on the changes to the safety standards and reporting requirements for onshore gas gathering lines that PHMSA proposed in an April 8, 2016 notice of proposed rulemaking (NPRM).\(^2\) The Gas Pipeline Advisory Committee (GPAC) will be considering those proposed changes at a public meeting on January 8 to 9, 2019, at the U.S. Department of Transportation’s headquarters in Washington, D.C., and GPA Midstream and API provided the joint position paper to PHMSA for consideration in preparing the materials that will be presented at the GPAC meeting.\(^3\)

\(^1\) GPA Midstream Association has served the U.S. energy industry since 1921. GPA Midstream is composed of nearly 100 corporate members that are engaged in the gathering and processing of natural gas into merchantable pipeline gas, commonly referred to in the industry as “midstream activities.” Such processing includes the removal of impurities from the raw gas stream produced at the wellhead as well as the extraction for sale of natural gas liquid products (NGLs) such as ethane, propane, butane, and natural gasoline or in the manufacture, transportation, or further processing of liquid products from natural gas. GPA Midstream membership accounts for more than 90% of the NGLs produced in the United States from natural gas processing. Additional information about GPA Midstream is available at https://gpaglobal.org/. Prior to April 2016, GPA Midstream was known as the Gas Processors Association.


\(^3\) 49 U.S.C. § 60115(c) (2017). The GPAC is a 15-member peer review committee responsible for advising PHMSA “on the technical feasibility, reasonableness, cost-effectiveness, and practicability” of any proposed gas pipeline
In the joint position paper, GPA Midstream and API addressed the three primary aspects of the NPRM: (1) PHMSA’s proposed changes to the definition of an onshore gas gathering line; (2) PHMSA’s proposed regulations for gas gathering lines in Class 1 locations; and (3) PHMSA’s proposed extension of the federal reporting requirements to all gas gathering lines, whether regulated or not. On the first topic, GPA Midstream and API opposed PHMSA’s proposal and urged PHMSA to retain the current definitions without modification. On the second topic, GPA Midstream and API generally supported PHMSA’s proposal, provided the regulations only applied to Class 1 gas gathering lines that are greater than 16 inches in nominal outside diameter and which have a maximum allowable operating pressure (MAOP) that produces a hoop stress of 20 percent or more of specified minimum yield strength (SMYS) for metallic lines or is more than 125 PSIG for non-metallic lines. On the third topic, GPA Midstream and API supported PHMSA’s proposal to apply the federal reporting requirements to Class 1 gas gathering lines, but only to a limited extent.

GPA Midstream is submitting this supplemental position paper to provide PHMSA with more detailed information on the criteria that should be used to determine if a pipeline is a regulated Class 1 gas gathering line. Specifically, GPA Midstream is urging PHMSA to allow operators to exclude pipeline segments that do not contain any buildings intended for human occupancy or identified sites within the potential impact radius (PIR). The addition of a PIR exception is supported by PHMSA’s integrity management (IM) regulations for gas transmission lines, PHMSA’s hazardous liquid pipeline safety regulations for rural gathering lines and low-stress lines, and the overarching risk-based philosophy of the pipeline safety regulations. A PIR exception will also ensure that PHMSA’s new regulations for Class 1 gas gathering lines satisfy the cost-benefit provision in the Pipeline Safety Act and are consistent with DOT policies, practices, and procedures and the President’s recent Executive Orders on regulatory reform, domestic energy independence, and economic growth.

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4 NPRM at 20,801-20,808, 20,827-20,828.
5 49 C.F.R. Part 192, Subpart O.
6 Id. § 195.11.
7 Id. § 195.12.
8 49 U.S.C. § 60102(b)(5) (stating that “[e]xcept where otherwise required by statute, the Secretary shall propose or issue a [pipeline safety] standard . . . only upon a reasoned determination that the benefits of the intended standard justify its costs”).
9 See e.g., Notification of Regulatory Review, 82 Fed. Reg. 45,750, 45,751 (Oct. 2, 2017) (discussing DOT’s obligation to minimize burdens imposed in regulations); Executive Order 13771 on Reducing Regulation and Controlling Regulatory Costs, which generally requires that federal agencies identify two existing regulations that will be repealed for every new regulation proposed or otherwise promulgated, 82 Fed. Reg. 9,339 (Feb. 3, 2017); (2) Executive Order 13777 on Enforcing the Regulatory Reform Agenda, which directs the head of all agencies to designate a Regulatory Reform Officer and create a Regulatory Reform Task Force to oversee the implementation of President Trump’s regulatory reform initiatives and policies, 82 Fed. Reg. 12,285 (Mar. 1, 2017); and (3) Executive Order 13783 on Promoting Energy Independence and Economic Growth, which requires federal agencies to review and make recommendations for addressing existing regulations and other actions that potentially burden the development or use of domestically-produced energy resources, 82 Fed. Reg. 16,093 (Mar. 31, 2017).
II. Analysis

In the joint position paper, GPA Midstream and API urged PHMSA to limit the regulations for Class 1 gas gathering lines to pipelines (1) that are greater than 16 inches in nominal outside diameter and (2) which have an MAOP that produces a hoop stress of 20 percent or more of SMYS for metallic lines or is more than 125 PSIG for non-metallic lines. With regard to the first criterion, GPA Midstream and API explained that pipelines greater than 16 inches in nominal outside diameter represent the new generation of large diameter gas gathering lines that PHMSA targeted in the NPRM. As to the second criteria, GPA Midstream and API agreed that the MAOP thresholds for metallic and non-metallic lines provided an acceptable, risk-based approach for distinguishing between higher pressure and lower pressure pipelines, so long as operators could use the non-metallic MAOP threshold if information about the stress level of steel pipe is unknown. GPA Midstream and API urged PHMSA to consider other risk-based concepts in reducing or minimizing the burden imposed by any new regulations, but did not offer any specific recommendations in that regard in the joint position paper.

GPA Midstream wishes to supplement the joint position paper by urging PHMSA to add an exception in the Class 1 gas gathering line regulations for pipeline segments that do not contain any buildings intended for human occupancy or identified sites within the potential impact circle. PHMSA’s IM regulations use a pipeline’s PIR, and the presence of identified sites\(^{10}\) or a certain number of buildings intended for human occupancy within the potential impact circle, in determining if a transmission line segment is in an HCA. The IM regulations define PIR as:

\[
\text{[T]he radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula } r = 0.69* (\text{square root of } (p*d^2)), \text{ where ‘r’ is the radius of a circular area in feet surrounding the point of failure, ‘p’ is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and ‘d’ is the nominal diameter of the pipeline in inches.}^{11}\]

The IM regulations further note that in the PIR calculation “0.69 is the factor for natural gas”, that “[t]his number will vary for other gases depending upon their heat of combustion”, and that “[a]n operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S (incorporated by reference, see §192.7) to calculate

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\(^{10}\) An identified site is defined in the IM regulations as “(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or (b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or (c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.” 49 C.F.R. § 192.903.

\(^{11}\) 49 C.F.R. § 192.903.
the impact radius formula.” The factor used in the PIR calculation for rich natural gas pipelines containing ethane, propane, or other heavier hydrocarbons is 0.73. PHMSA provides additional guidance for using PIR to determine if a gas transmission line segment is in an HCA in the IM regulations and Appendix E.I to Part 192.

As with the IM regulations, the PIR concept can be used to focus PHMSA’s new regulations for Class 1 gas gathering lines to areas that present an actual risk to people or property. Operators of large-diameter, high-pressure gas gathering lines should have all of the information necessary to perform a PIR calculation for a pipeline segment. GPA Midstream supports using a nominal outside diameter criteria (greater than 16 inches) and MAOP threshold (20 percent or more of SMYS for metallic lines or is more than 125 PSIG for non-metallic lines) to determine the regulatory status of Class 1 gas gathering lines, and operators can use that same information in performing the PIR calculation. The third element in the formula, the gas factor, is provided directly in the regulations, i.e., 0.69 for lean gas systems and 0.73 for rich gas systems. Once the PIR calculation is performed, operators can follow the approach outlined in the IM regulations and Appendix E.I to determine if there are any buildings intended for human occupancy or identified sites within the potential impact circle for a pipeline segment.

The concepts that PHMSA uses to determine the regulatory status of rural gathering lines and low-stress lines in the hazardous liquid pipeline safety regulations support the addition of a PIR exception for Class 1 gas gathering lines. PHMSA uses three criteria to determine if a rural gathering line transporting petroleum is regulated: (1) nominal outside diameter, (2) maximum operating pressure (greater than 20 percent of SMYS or, if the stress level is unknown, more than 125 psi), and (3) potential environmental impact (located in or within ¼ mile of an unusually sensitive area). PHMSA uses the same three criteria in categorizing the regulatory status of low-stress hazardous liquid lines in rural areas. Adding a PIR exception, which is analogous to the potential environmental impact criteria that PHMSA uses for petroleum gathering lines and hazardous liquid low-stress lines in rural areas, to the nominal outside diameter criteria and MAOP threshold for Class 1 gas gathering lines creates a risk-based regime for rural gas gathering lines that is consistent with the hazardous liquid pipeline safety regulations.

A PIR exception will ensure that PHMSA’s new regulations for Class 1 gas gathering lines satisfy the cost-benefit provision in the Pipeline Safety Act and are consistent with DOT policies, practices, and procedures and the President’s recent Executive Orders on regulatory reform, domestic energy independence, and economic growth. As GPA Midstream and API discussed in the joint position paper, the costs of the changes proposed in the NPRM would exceed the benefits by more than $28 billion during the initial 15-year compliance period. That cost-benefit analysis will be significantly improved if PHMSA retains the existing definitions for

12 Id.
13 Id. §§ 195.11, 195.12.
14 Id. 195.11(a).
15 Id. 195.12(b).
16 49 U.S.C. § 60102(b)(5) (stating that “[e]xcept where otherwise required by statute, the Secretary shall propose or issue a [pipeline safety] standard . . . only upon a reasoned determination that the benefits of the intended standard justify its costs”).
17 See e.g., supra note 9.
onshore gas gathering, restricts the new regulations to Class 1 gas gathering lines that are greater than 16 inches in nominal outside diameter, and limits the new reporting requirements for gathering line operators. However, PHMSA does not have comprehensive safety data on Class 1 gas gathering lines, and the new regulations will still apply to many pipeline segments that do not present a risk to people or property if a PIR exception is not added to the final rule. Treating Class 1 pipeline segments that have buildings intended for human occupancy or identified sites within the potential impact circle the same as those that do not undermines the risk-based philosophy of PHMSA’s regulations and imposes an undue regulatory burden on operators.

The cost of allowing Class 1 gathering line operators to use a PIR exception will be more than offset by the benefits of limiting the new regulations to areas that present an actual risk to public safety. Operators are already required to complete class location studies to determine the regulatory status of onshore gas gathering lines, and those studies produce information on the presence or absence of buildings intended for human occupancy and identified sites that can also be used in evaluating the potential impact circle for a pipeline segment. Making that exception discretionary, rather than mandatory, will further minimize the burden as operators can simply choose not to perform the PIR calculation or supplemental analysis if the costs of doing so exceed the benefits.

For these reasons, GPA Midstream suggests that PHMSA adopt the following regulatory language in the final rule. Note that the language is the same as what GPA Midstream and API offered in the joint position paper, with the addition of the PIR exception for Type C lines in italics:

§ 192.8(c) How are gathering lines and regulated onshore gathering lines determined?

<table>
<thead>
<tr>
<th>Type</th>
<th>Feature</th>
<th>Area</th>
<th>Safety buffer</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>—Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part —Non-metallic and the MAOP is more than 125 PSIG (862 kPa)</td>
<td>Class 2, 3, or 4 location (see §192.5)</td>
<td>None.</td>
</tr>
<tr>
<td>B</td>
<td>—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the gathering line is in Area 2(b) or 2(c), the additional</td>
<td>Area 1. Class 3 or 4 location Area 2. An area within a Class 2 location the operator</td>
<td>If the gathering line is in Area 2(b) or 2(c), the additional</td>
</tr>
<tr>
<td><strong>C</strong></td>
<td><strong>—Metallic pipe greater than 16 inches in nominal outside diameter and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must either determine the stress level according to the applicable provisions in subpart C of this part, or use the MAOP limitation for non-metallic pipe.</strong></td>
<td><strong>—Non-metallic pipe greater than 16 inches in nominal outside diameter and the MAOP is more than 125 PSIG (862 kPa) determines by using any of the following three methods:</strong></td>
<td><strong>—Non-metallic and the MAOP is 125 PSIG (862 kPa) or less.</strong></td>
</tr>
<tr>
<td>—Non-metallic and the MAOP is 125 PSIG (862 kPa) or less.</td>
<td>(a) A Class 2 location. (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings; or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.</td>
<td>lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2(b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.</td>
<td>Class 1 location. <em>An operator may exclude a pipeline segment that does not have any buildings intended for human occupancy or identified sites within the potential impact radius as determined in accordance with §192.903 and figure E.I.A. in appendix E.</em> None</td>
</tr>
</tbody>
</table>
III. Conclusion

GPA Midstream shares PHMSA’s commitment to pipeline safety and appreciates the opportunity to submit this supplemental position paper on the proposed changes to the safety standards and reporting requirements for onshore gas gathering lines. If you have questions or concerns, please do not hesitate to contact me directly at (202) 279-1664 or by email at mhite@gpamidstream.org.

Sincerely,

Matthew Hite
Vice President of Government Affairs
GPA Midstream Association
Cost and Benefit Impact Analysis of the PHMSA Natural Gas Gathering and Transmission Safety Regulation Proposal

July 1, 2016

Prepared for:
American Petroleum Institute
1220 L Street NW
Washington, D.C. 20005

Submitted by:
ICF International

Contact:
Harry Vidas
703-218-2745
Executive Summary

ICF International has been asked by American Petroleum Institute (API) to evaluate the cost and benefit impact of the PHMSA safety regulation proposal (Part 191 and 192) dated April 8, 2016, but does not consider information presented in webinars after this date. ICF’s analysis includes validating the methodology and assumptions of the PHMSA cost and benefit calculations and making changes as necessary as well as determining any missing costs not included in the PHMSA cost analysis.

ES.1 Overall Summary of Gathering and Transmission Results

The table below displays ICF’s overall results as a present value over 15 years with a discount rate of 7%. These results include ICF’s estimates for missing costs in gathering and transmission as well as ICF’s revisions to PHMSA’s RIA calculations for costs and benefits in both sectors. In this analysis, the low estimate benefits have been reduced from $3,234 million to $306 million, the high estimate benefits from $3,738 million to $568 million. The overall costs have increased from PHMSA’s $597 million to the ICF estimate of $33,416 million. The sections below provide the explanations behind these differences.

Table 1

<table>
<thead>
<tr>
<th>Topic Area</th>
<th>ICF Missing and Revised Calculations$^1$</th>
<th>PHMSA RIA$^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Benefits - Low</td>
<td>Benefits - High</td>
</tr>
<tr>
<td>1 Re-establish MAOP, Verify Material Properties, and Integrity Assessment Outside HCAs</td>
<td>$138.7</td>
<td>$401.0</td>
</tr>
<tr>
<td>2 Field Repair of Damages - (More Timely Repairs)</td>
<td>n.e.</td>
<td>n.e.</td>
</tr>
<tr>
<td>3 Management of Change Process Improvement</td>
<td>$16.4</td>
<td>$16.4</td>
</tr>
<tr>
<td>4 Corrosion Control</td>
<td>$96.1</td>
<td>$96.1</td>
</tr>
<tr>
<td>5 Pipeline Inspection Following Extreme Events</td>
<td>$4.7</td>
<td>$4.7</td>
</tr>
<tr>
<td>6 MAOP Exceedance Reports and Records Verification</td>
<td>n.e.</td>
<td>n.e.</td>
</tr>
<tr>
<td>7 Launcher/Receiver Pressure Relief</td>
<td>$6.7</td>
<td>$6.7</td>
</tr>
<tr>
<td>8 Expansion of Gathering Regulation</td>
<td>$43.3</td>
<td>$43.3</td>
</tr>
<tr>
<td>Total for Gathering and Transmission Sectors</td>
<td>$305.9</td>
<td>$568.2</td>
</tr>
</tbody>
</table>

n.e. = not estimated

1. Figures for ICF Missing and Revised Calculations do not account for select costs as outlined in Section 4 of this report.

2. PHMSA RIA values displayed are the average annual values in Table ES-6 of the RIA multiplied by 15 to get the 15 year value. This may be slightly off due to rounding in Table ES-6.
ES.2 Summary of Gathering Sector

ICF determines that many of the costs associated with the gathering sector are completely missing from the PHMSA RIA calculations (a through o) or are incorrectly calculated (p through t), as follows:

(a) The RIA does not account for the up-front time and associated costs to interpret the rule and determine applicability to various pipe segments within each company’s system.

(b) The proposal requires (192.607) all operators verify pipeline material that do not have “reliable, traceable, verifiable, and complete material documentation records” to conduct material testing of their pipe. The RIA does not calculate the cost of this requirement.

(c) The proposal requires (192.619, 192.624) that all operators determine or verify Maximum Allowable Operating Pressure (MAOP). This requirement creates substantial costs for operators who must determine MAOP. Some gathering operators either cannot utilize the five-year look-back period or do not already know MAOP. Of those operators that know the MAOP or can use the 5-year lookback option, all must verify if located in Class 3, Class 4, or Moderate or High Consequence Area (MCA or HCA, respectively) location. The RIA does not include the cost of MAOP determination for such operators.

(d) The proposal requires (191.23) operators to report safety-related conditions including the exceedance of MAOP. An operator must know the MAOP to know if this exceedance occurs, which requires the determination of MAOP. This applies to all pipeline, regardless of regulation. The RIA does not account for this cost.

(e) The proposal requires (192.163) operators to construct compressor buildings under certain standards. The RIA does not include this cost to build a noncombustible-material building for new compressor stations built in the future that would not have this requirement without the proposal.

(f) The proposal requires (192.706) operators perform periodic leak surveys and assessments. The RIA assumes that operators fix all conditions found during surveys. However, some operators may only monitor certain conditions and may not necessarily fix them within a set timeframe. The RIA does not consider the cost of fixing these monitored conditions. Additionally, the RIA does not take into account the incremental cost to fix a large number of conditions within an accelerated timeframe.

(g) The proposal requires (192.321) operators of above-ground plastic pipe in operation for greater than two years install such pipeline below ground with a specified minimum cover. The RIA does not include the cost for re-installing existing plastic pipe below ground.

(h) The proposal requires (192.105) operators to design newly installed pipeline under certain material standards. This might require higher grade steels, thicker walls, or the substitution of steel for plastic and composites. The RIA does not include the incremental costs for installing higher grade gathering pipe in the future than currently necessary to comply with the proposed design requirements for pipe.

(i) The proposal requires (192.183) operators to construct any installed vaults under certain design requirements. The RIA does not include the incremental costs to comply with specific structural design requirements for vaults on new gathering lines installed in the future.

(j) The proposal requires (192.619 and 192.624) operators to assess newly defined moderate consequence areas (MCA) for MAOP determination and verification. To determine whether a
pipeline must comply, an operator must identify MCA areas, if any, using a Geographic Information System (GIS). The RIA does not account for the cost to identify these areas using GIS.

(k) The proposal requires (192.706) operators of Type A Area 2 to perform periodic leak surveys in order to maintain safe operation of a pipeline. The RIA does not consider this cost.

(l) The proposal requires (192.13) operators to perform a management of change process as well as reestablish records when gathering systems change hands. The RIA does not consider these costs.

(m) The proposal requires (192.478 and 192.465) operators adhere to internal and external corrosion requirements for operating gathering lines. This requires performing periodic surveys to monitor the condition of an operating pipe to ensure public safety. The RIA includes a cost for this requirement; however, these costs do not account for all specified requirements. Hence, ICF developed an estimate of additional costs for this requirement.

(n) The proposal requires (192.613) operators to conduct an inspection of all onshore pipeline and following an extreme weather event within 72 hours of cessation of the event. ICF considers this to include the cost to develop a process and perform inspection. The RIA does not consider these costs for gathering lines.

(o) The proposal requires (192.711, 192.713) operators to fix all conditions identified during leak surveys and assessments. Operators have historically monitoring conditions without necessarily fixing them. Therefore, a backlog of conditions exists that will need repair when the proposed rule comes into effect. The RIA does not consider the cost to address this backlog of conditions.

(p) The proposal requires (191.17) operators to complete and submit annual reports for all pipeline to PHMSA. The RIA provides an estimate of cost to submit these annual reports, but ICF considers these costs underestimated. We include a revision of these costs in our cumulative cost calculations.

(q) In the RIA, PHMSA assumes that 3% percent of newly regulated Type A Area 2 pipe is owned by a company not already regulated. ICF considers 80% of newly regulated Type A Area 2 pipe is owned by a company not already regulated.

(r) In the RIA, the pre-regulation occurrence of incidents were estimated incorrectly by taking the offshore incidents from 2001-2005 and applying them to Type A Area 2. ICF considers onshore incidents from 2001-2005.

(s) In the RIA, the post-regulation occurrence of incidents were estimated by taking the reported Type B incidents from 2010-2014 and applying them to Type A Area 2. ICF considers onshore incidents from Type A Area 1 to be a better estimate for the high stress Type A Area 2 pipeline.

(t) Finally in the RIA, Table 6-8 estimates the gas lost from onshore and offshore incidents. ICF considers onshore, natural gas, Type A and B pipelines for determining gas lost.

The following table shows ICF’s new cost estimates for various parameters for gathering systems that impact operators based on the proposed safety regulation. For each cost parameter, ICF determines a net present value cost over a 15-year period using a 7% discount rate. (ICF has incorporated the revised benefit estimates discussed in items (r)-(t) in the overall table above, Table 1.) The total cost impact of the proposed rule on gathering line operations amounts to $27.1 billion.
### 15 Year Net Present Value Costs for Gathering Lines (Millions; 2015$)

<table>
<thead>
<tr>
<th>Topic Area</th>
<th>Total (NPV with discount rate 7%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Implementation of the Rule</td>
<td>$264.4</td>
</tr>
<tr>
<td>b. Material Verification</td>
<td>$315.0</td>
</tr>
<tr>
<td>c. MAOP Determination for Regulated Pipeline</td>
<td>$4,258.9</td>
</tr>
<tr>
<td>d. MAOP Determination for Unregulated Pipeline</td>
<td>$19,932.6</td>
</tr>
<tr>
<td>e. Compressor Stations</td>
<td>$14.4</td>
</tr>
<tr>
<td>f. Field Repair of Damages</td>
<td>$35.2</td>
</tr>
<tr>
<td>g. Construction</td>
<td>$86.9</td>
</tr>
<tr>
<td>h. Design Pressure</td>
<td>$499.2</td>
</tr>
<tr>
<td>i. Vaults</td>
<td>$1.6</td>
</tr>
<tr>
<td>j. Moderate Consequence Area Assessment</td>
<td>$543.5</td>
</tr>
<tr>
<td>k. Leak Surveys</td>
<td>$277.8</td>
</tr>
<tr>
<td>l. Management of Change</td>
<td>$778.4</td>
</tr>
<tr>
<td>m. Corrosion Control and Test Stations</td>
<td>$68.9</td>
</tr>
<tr>
<td>n. Pipeline Inspection Following Extreme Events</td>
<td>$49.1</td>
</tr>
<tr>
<td>o. Repairing Backlog of Conditions</td>
<td>$10.2</td>
</tr>
<tr>
<td><strong>a-o. Subtotal Cost for Items Missing from the RIA</strong></td>
<td><strong>$27,136.2</strong></td>
</tr>
<tr>
<td><strong>p-q. Subtotal Cost for Revised Items</strong></td>
<td><strong>$1,736.0</strong></td>
</tr>
<tr>
<td><strong>Total Costs</strong></td>
<td><strong>$28,872.2</strong></td>
</tr>
</tbody>
</table>
ES.2.1 Gathering Compliance Costs by Company Size

In order to estimate the impact of the regulation on companies of different sizes, ICF breaks the gathering compliance costs into costs incurred per company regardless of mileage versus those costs which are a function of mileage.

Table 3 shows gathering mile costs on an annual basis. ICF estimates each company will incur 7.6% of those costs creating a cost per company of $40,660. The remaining 92.4% of the costs lead to a per mile cost of $4,451.

Table 3

<table>
<thead>
<tr>
<th>Annual Compliance Costs (7% NPV divided by 15 years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Annual cost for gathering</td>
</tr>
<tr>
<td>Fraction of costs that are per-company and unrelated to mileage</td>
</tr>
<tr>
<td>Annual cost allocated on per-company basis</td>
</tr>
<tr>
<td>Annual cost allocated on per-mile basis</td>
</tr>
<tr>
<td>Cost per company (unrelated to mileage)</td>
</tr>
<tr>
<td>Regulatory compliance cost per mile</td>
</tr>
</tbody>
</table>

Table 4 shows the approximate impact of the proposed regulation as estimated by ICF broken out by size of gathering company. The number of companies and the distribution of companies by size comes from the data analysis described in Section 2.1 of this report. ICF assumes the volumes gathered as equal to EIA estimates of onshore U.S. gross natural gas withdrawals in 2014 (the last full year of data). ICF also estimates revenues per Mcf of gas gathered. Additionally, ICF assumes total volumes gathered and revenues as proportional to mileage of gathering line among the three company-size segments.

For the gathering system as a whole, compliance costs average approximately 22% of revenues. However, for the smallest companies, the estimated annual compliance cost nearly equals estimated annual revenues from gathering fees. This disproportionate impact on small gatherers occurs because many of the costs incurred by the gatherers derive from regulatory analysis, set-up, and training costs which remain similar for each company regardless of its size.
Table 4

Impact of Gathering System Regulations by Company Size

<table>
<thead>
<tr>
<th>Size Segment Label</th>
<th>Small Companies</th>
<th>Medium Companies</th>
<th>Large Companies</th>
<th>All Gatherers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum Miles per Company in Size Segment</td>
<td>0</td>
<td>10</td>
<td>100</td>
<td>0</td>
</tr>
<tr>
<td>Maximum Miles per Company in Size Segment</td>
<td>10</td>
<td>100</td>
<td>35,000</td>
<td>35,000</td>
</tr>
<tr>
<td>Company Count in Size Segment</td>
<td>2,223</td>
<td>921</td>
<td>453</td>
<td>3,597</td>
</tr>
<tr>
<td>Miles of Gathering Line in Size Segment</td>
<td>5,994</td>
<td>25,973</td>
<td>367,613</td>
<td>399,579</td>
</tr>
<tr>
<td>Miles of Gathering Line per Company</td>
<td>3</td>
<td>28</td>
<td>811</td>
<td>111</td>
</tr>
<tr>
<td>Approximate Annual Gas Volumes (Mcf) in Size Segment</td>
<td>435,187,050</td>
<td>1,885,810,550</td>
<td>26,691,472,400</td>
<td>29,012,470,000</td>
</tr>
<tr>
<td>Approximate Annual Gas Volumes (Mcf) per Company</td>
<td>195,770</td>
<td>2,047,942</td>
<td>58,892,711</td>
<td>8,065,741</td>
</tr>
<tr>
<td>Approximate Annual Gathering Fees per Company</td>
<td>$58,731</td>
<td>$614,383</td>
<td>$17,667,813</td>
<td>$2,419,722</td>
</tr>
<tr>
<td>Annual Compliance Cost in Size Segment (7% NPV /15 years)</td>
<td>$117,062,433</td>
<td>$153,046,895</td>
<td>$1,654,700,826</td>
<td>$1,924,810,153</td>
</tr>
<tr>
<td>Annual Compliance Cost per Company (7% NPV /15 years)</td>
<td>$52,661</td>
<td>$166,205</td>
<td>$3,650,972</td>
<td>$535,115</td>
</tr>
<tr>
<td>Annual Compliance Cost as % of Annual Gathering Revenues</td>
<td>90%</td>
<td>27%</td>
<td>21%</td>
<td>22%</td>
</tr>
</tbody>
</table>

ES.3 Summary of Transmission Sector

ICF determines that some of the costs associated with the transmission sector are completely missing from the PHMSA RIA calculations (a through d below) and determines that several key assumptions on estimating benefits and costs for the transmission sector are not representative of the current state of industry practices and the true cost impacts of the proposed rules (e through k below). The key assumptions and calculations requiring additions and revisions are as follows:

(a) The proposal requires (192.710 and 192.713) MCA mileage under pipeline assessment to repair conditions. These conditions are often times only monitored and not necessarily fixed within a set timeframe. The RIA does not adequately calculate the cost of this requirement.

(b) The proposal requires (192.713) operators repair pipeline under a specified timeframe. The RIA does not include repair costs for non-HCA and non-MCA mileage.

(c) The proposal modifies (192.3) the definition of gathering lines, requiring lines downstream of gas processing facilities (referred to as incidental pipe) that are now identified as gathering to comply with the entire transmission line regulation. This incidental transmission mileage is not accounted for in the RIA.
(d) The proposal requires (192.713) operators to fix all conditions identified during leak surveys and assessments. Operators have historically monitoring conditions without necessarily fixing them. Therefore, a backlog of conditions exists that will need repair when the proposed rule comes into effect. The RIA does not consider the cost to address these backlog of conditions.

(e) The RIA disregards operator feedback for the cost to upgrade pipeline to accommodate ILI, hence ICF modified the upgrade cost to reflect operator input more closely.

(f) The RIA estimates vendor costs but does not account for costs associated to the company for scheduling, implementing, supervising and verifying the work. ICF added a general and administrative cost to all vendor costs.

(g) The proposal requires (192.933) the repair of conditions immediately. The RIA assumes that all conditions found in an HCA during surveys are currently fixed. Many conditions currently are only monitored and not necessarily fixed within a set timeframe. The cost of fixing conditions that are only currently monitored is not a part of the RIA.

(h) The proposal requires (192.613) operators to conduct an inspection of all onshore pipeline and following an extreme weather event within 72 hours of cessation. ICF considers this as the cost to develop a process and perform inspection. The RIA does not consider this cost.

(i) The RIA underestimates the cost to conduct ILI, and so ICF made adjustments to the additional tools including Spiral MFL and crack tools.

(j) The RIA underestimates the cost to conduct a pressure test and so ICF made adjustments to these costs.

(k) The RIA underestimates the time to implement a management of change program in table 3-67.

(l) The RIA assumes a very large economic benefit associated with the reduced cost for tensile testing (192.107) which is added language in the regulation. ICF did not include this benefit because it does not comply with the “costs without new regulation” versus “cost with new regulation” concept that must be used for cost-benefit analyses of federal regulations.

(m) The RIA took a simple average of incidents in Table E-3 associated with incidents in HCA areas, which in turn over represents the true mean of these incidents. ICF took a power law distribution and applied it to the 23 incidents to achieve a more reasonable mean cost per incident.

The following table shows ICF’s new cost estimates for various parameters for transmission systems that impact operators based on the proposed safety regulation. For each cost parameter, ICF determines a net present value cost over a 15-year period using a 7% discount rate. (ICF has incorporated the revised benefit estimates discussed in items (l) – (m) in the overall table above, Table 1.) The total cost impact of the proposed rule on transmission operations amounts to $4.5 billion.
### Table 5

<table>
<thead>
<tr>
<th>Topic Area</th>
<th>Total (NPV with discount rate 7%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. MCA Field Repair of Damages</td>
<td>$591</td>
</tr>
<tr>
<td>b. Non-MCA/Non-HCA Miles Field Repair of Damages</td>
<td>$1,594</td>
</tr>
<tr>
<td>c. Incidental Mileage</td>
<td>$270</td>
</tr>
<tr>
<td>d. Repairing Backlog of Conditions</td>
<td>$923</td>
</tr>
<tr>
<td>a-d. Subtotal Cost for Missing Items</td>
<td>$3,377</td>
</tr>
<tr>
<td>e-k. Subtotal Cost for Revised Items</td>
<td>$1,167</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$4,543.9</strong></td>
</tr>
</tbody>
</table>

### ES.4 Discussion of Benefits

During review of PHMSA’s Preliminary Regulatory Impact Assessment, ICF found a number of inconsistencies in the calculations, with errors from Tables 6-1 and Tables 6-6 of the RIA having a significant impact on results. Table 6-1 is applying onshore and offshore incidents to onshore gathering line mileage. Removing offshore gathering incidents from onshore mileage over the same time period results in a change from 0.329 incidents per thousand miles to 0.144 incidents per thousand miles. Further, PHMSA pulled total costs when calculating Table 6-6’s “other incident costs”. This effectively double counted costs associated with fatalities, injuries and evacuations. By making the corrections to Table 6-1 and 6-6, the benefits from Topic Area 8 drops from $169.5 million to $43.3 million over the fifteen year period (Total NPV with discount rate 7%). ICF includes a complete listing of all inconsistencies in Appendix A.

ICF also takes issue with PHMSA’s calculation of the average economic consequences for certain types of incidents related to HCAs in a table entitled “Table E-3. Historical Consequences of Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods Located in HCAs (2003-2015; 2015$).” This table takes a simple average of the consequences for 23 incidents that occurred over 13 years to compute an average of $23.4 million per incident. An analysis of the underlying data indicates that a single incident contributed 98.9% of the total consequences from the 23 incidents. Because the sample size is so small and so heavily skewed, it raises the question of how random factor commonly referred to as the “luck of the draw” might have influenced the calculated average and what a more sophisticated analysis of the data might reveal is a better estimate of the mean value for this variable. ICF conducts such an analysis assuming that consequences follow a power law distribution. This analysis suggests a better estimate of the average consequences to be expected from incidents in HCA areas from causes detectable by modern integrity assessment methods as approximately $6.7 million rather than the $23.4 million calculated by a simple average of the 23 incidents.

### ES.5 Structure of Report

The structure of this report is as follows. The Background section provides the context to the analysis presented in this report. The Detailed Cost Discussion for Gathering section provides a detailed discussion.
of each cost parameter for gathering systems either missing or revised from the analysis shown in the RIA. The Detailed Cost Discussion for Transmission section provides a discussion of the cost parameters that were missing or required revisions, including the application of the power law distribution. The Significant Costs Lacking Data for Analysis section provides a discussion of known cost parameters without easily applicable methods of estimation from present data. Appendix A provides a listing of a variety of issues ICF determined when reviewing PHMSA’s calculations. Appendices B, C, and D provide all recalculated tables from the RIA that relate to gathering systems, transmission systems, and the RIA appendix itself respectively.
Foreword
Introduction

This recommended practice is intended to address developments in the oil and gas industry, particularly the emergence of larger diameter, higher pressure gas gathering lines in shale plays. Most gas gathering lines in the United States do not share these operating characteristics, and the risk-based provisions in this recommended practice are not necessarily appropriate for the smaller diameter, lower pressure gas gathering lines that still predominate throughout industry.

The provisions in this recommended practice are intended to work together and should not be considered in isolation. The provisions for the design, construction, testing, operation, and maintenance of rural gas gathering lines are not necessarily appropriate under different definitions.

Background

In August 2011, DOT published an advance notice of proposed rulemaking (ANPRM) asking for public comment on the need to change the federal pipeline safety standards for gas gathering lines in 49 C.F.R. Part 192. (Docket No. PHMSA-2011-0023; 76 Fed. Reg. 53,086). Adopted in a March 2006 final rule, DOT’s regulations require operators to use the provisions in API Recommended Practice 80, “Guidelines for the Definition of Onshore Gas Gathering Lines,” 1st edition, April 2000, (RP 80), to determine if a pipeline is an onshore gas gathering line, subject to certain additional regulatory limitations in Part 192. If a pipeline is an onshore gas gathering line, DOT’s regulations require operators to determine if the pipeline meets the definition of a “regulated onshore gas gathering line”. Under the March 2006 final rule, regulated onshore gas gathering lines are limited to pipelines in more populated, Class 2, 3, or 4 locations. Onshore gas gathering lines in less populated, Class 1 locations are exempt from regulation.

In April 2016, DOT issued a notice of proposed rulemaking (NPRM) with potential changes to the regulations for onshore gas gathering lines (Docket No. PHMSA-2011-0023; 81 Fed. Reg. 20,721). The proposed changes included new definitions for onshore production and gathering operations and new safety standards for certain gas gathering lines in Class 1 locations. After submitting comments in response to the NPRM, the American Petroleum Institute (API) formed a working group to consider whether to develop a new recommended practice for the safety of onshore gas gathering lines. API decided to move forward with that initiative at the conclusion of the working group’s deliberations.

In January 2018, API convened an initial meeting in Houston, Texas, to discuss the development of a new recommended practice for onshore gas gathering lines. Nearly 100 people participated in the meeting, including representatives from pipeline companies, industry trade organizations, advocacy groups, and regulatory bodies. API held additional meetings throughout 2018 and 2019 before reaching a consensus on the provisions in this recommended practice, which are intended to apply to the design, construction, testing, operation, and maintenance of large diameter gas gathering lines in rural areas.
1 Scope

1.1 General

This recommended practice contains provisions relating to design, construction, testing, corrosion control, operation, and maintenance of onshore gas gathering lines as defined in API RP 80, in Class 1 (3.1.4) or Class 2 locations (3.1.5) that are greater than 12.75 inches in nominal outside diameter.

1.2 New Pipelines

Except where otherwise noted, the provisions of this recommended practice apply to new pipelines.

1.3 Existing Pipelines

The design, construction, and testing provisions in Section 5 do not apply to existing pipelines. Except where otherwise noted, the external and internal corrosion control, and operation and maintenance provisions in Sections 6 and 7 apply to existing pipelines.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the reference document (including any amendment) applies.

API Recommended Practice 80, Guidelines for the Definition of Onshore Gas Gathering Lines

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1 active corrosion

Continuing corrosion, which, unless controlled, could result in a condition that is detrimental to public safety or the environment

3.1.2 building intended for human occupancy

A residential, commercial, or industrial building that is intended to be occupied by people, such as a house, apartment, store, or office.

3.1.3 class location unit

An onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous one-mile (1.6 kilometers) length of pipeline.

3.1.4 class 1 location

A class location unit that has 10 or fewer buildings intended for human occupancy.

3.1.5 class 2 location

Any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

3.1.6 component

Part of a pipeline other than pipe that is subject to system pressure.

3.1.7 existing pipeline
A pipeline placed into service on or before the adoption of this recommended practice.

3.1.8 impracticable
An activity that cannot be accomplished without incurring unnecessary hardship or employing unreasonable measures.

3.1.9 maximum allowable operating pressure
MAOP
The maximum pressure at which a pipeline may be operated.

3.1.10 new pipeline
A pipeline that is placed into service, or an existing pipeline that is replaced or relocated, after adoption of this recommended practice.

3.1.11 pipe
A tube manufactured with metallic or non-metallic (plastic, composite, or other) material.

3.1.12 pipeline
Line pipe and components.

3.1.13 potential impact circle
A circle of radius equal to the potential impact radius (PIR) as measured from the centerline of a pipeline.

3.1.14 potential impact radius
PIR
The radius of a circle as measured from the centerline of a pipeline calculated using Equation 1. See section 4.4.

3.1.15 hain
A small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive).

3.1.16 recognized and generally accepted industry practices
Codes, standards, technical reports, or recommended practices that provide established methods for performing pipeline design, construction, testing, operation, or maintenance activities.

4 Risk Categorization

4.1 General
This section contains the provisions for determining whether a pipeline is a Type C gathering line or Type D gathering line.

4.2 Type C Gathering Line Criteria
Figure 1 describes criteria for Type C gas gathering lines.

Figure 1 - Type C Gathering Line Criteria

<table>
<thead>
<tr>
<th>Diameter</th>
<th>MAOP (Metallic)</th>
<th>MAOP (Non-Metallic)</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Pipeline is greater than 12.75” nominal outside diameter. MAOP produces a hoop stress of 20% or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in Section 4.4 or use the MAOP limitation that applies to non-metallic lines (more than 125 PSIG). MAOP is more than 125 PSIG. Operator may exclude a pipeline that is greater than 12.75” in nominal outside diameter up to and including 16” that does not contain any buildings intended for human occupancy or hain within the class location unit or potential impact radius (PIR) as determined in accordance with Section 4.4.

4.3 Type D Gathering Line Criteria

All other gathering lines greater than 12.75" in nominal outside diameter that do not meet the Type C criteria can be considered Type D.

4.4 Potential Impact Radius

The operator may calculate the potential impact radius using Equation 1 or assume that PIR is 660 feet (200 meters).

4.4.1 Calculating PIR

The potential impact radius of a pipeline may be determined by Equation 1, where ‘r’ is the radius of a circular area in feet surrounding the point of failure, ‘0.73’ is the factor for rich natural gas, ‘p’ is the MAOP of the pipeline segment in pounds per square inch, and ‘d’ is the nominal diameter of the pipeline in inches.

\[ r = 0.73 \sqrt{pd^2} \]  

Where,

- \( r \) is the radius of a circular area in feet surround the potential point of failure
- 0.73 is the rich natural gas factor

**NOTE** The lean gas factor of 0.69 may be used when transporting dry gas

- \( p \) is the MAOP of the pipeline segment in pounds per square inch
- \( d \) is the nominal diameter of the pipeline in inches

4.4.1.1 Natural Gas Factor

4.4.1.1.1 The rich natural gas factor of 0.73 shall be used in the potential impact radius calculation, unless the operator determines that the use of the lean natural gas factor of 0.69 is justified.

4.4.1.1.2 To justify the use of the lean natural gas factor in a potential impact radius calculation, an operator shall demonstrate that the gross heating value of the gas composition is less than or equal to 1100 Btu/cubic foot.

4.4.1.3 If an operator uses the lean natural gas factor in a potential impact radius calculation, appropriate documentation justifying that determination should be kept for the life of the pipeline.

4.4.1.4 If the quality of the gas changes from dry to wet gas, requiring a different gas factor, PIR shall be re-calculated for the new composition.

4.4.2 Potential Impact Circle
The operator shall determine whether the potential impact circle contains either of the following:

- One or more buildings intended for human occupancy; or
- One or more occupied sites.

4.4.2.1 In making a determination under Section 4.4, the potential impact circle extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either a building intended for human occupancy or a occupied site to the outermost edge of the last contiguous potential impact circle that contains either a building intended for human occupancy or a occupied site.

4.4.2.2 An operator should incorporate the potential deviation of the pipeline centerline when determining the potential impact circle.

4.4.2.3 Operators should consider potential inaccuracies in potential impact circle factors, including:

- Centerline data
- Geospatial information
- Pipe diameter

4.4.3 Documentation

4.4.3.1 Operators shall document the means by which PIR was calculated and retain this documentation until the next PIR calculation is performed.

5 Design, Construction, and Testing

5.1 General

This section contains design, construction, and testing provisions for new gathering pipelines.

5.2 Requirements for Type C Gathering Line Systems

5.2.1 Type C gathering line systems shall be designed, constructed, and tested in accordance with 49 CFR 192.9(d)(1).

5.2.2 An operator shall keep appropriate records documenting the design of pipe and components for the life of the pipeline.

5.3 Requirements for Type D Gathering Line Systems

5.3.1 General

An operator shall follow the requirements given in 5.3.2 to 5.3.7 for Type D Gathering Line systems.

5.3.2 Material Requirements

5.3.2.1 Materials for pipe and components shall be:

- Capable of maintaining structural integrity,
- Compatible with product to be transported, and
- Qualified for use in accordance with recognized and generally accepted industry practices.

5.3.2.2 An operator should keep appropriate records documenting the materials for pipe and components for the life of the pipeline.

5.3.3 Design Requirements

5.3.3.1 Pipe and components shall be designed in accordance with recognized and generally accepted industry practices to withstand internal pressures and external loads.

5.3.3.2 An operator should keep appropriate records documenting the design of pipe and components for the life of the pipeline.

5.3.4 Construction Requirements
5.3.4.1 A pipeline shall be constructed in accordance with recognized and generally accepted industry practices.

5.3.4.2 An operator should keep appropriate construction records for the life of the pipeline.

5.3.5 Cover Requirements

5.3.5.1 If a pipeline is buried at the time of installation, an operator should consider providing at least 30" of cover in normal soil and 18" of cover in consolidated rock for the purpose of integrity management and damage prevention.

5.3.5.2 If a pipeline is buried at the time of installation, an operator should consider providing additional cover or additional protective measures at rail, road, or water crossings.

5.3.5.3 If a pipeline is not buried at the time of installation, or a pipeline is buried with less cover than recommended in Section 5.3.5.1, an operator should consider implementing other measures to protect the pipeline from potential threats.

5.3.6 Location

An operator should keep appropriate records documenting the location of pipe and components for the life of the pipeline.

5.3.7 Testing

5.3.7.1 A pipeline shall be tested in accordance with recognized and generally accepted industry practices to substantiate MAOP.

5.3.7.2 Testing to substantiate MAOP for a component shall not be required if a component carries a pressure rating established in accordance with recognized and generally accepted industry practices, including a manufacturer’s certification.

5.3.7.3 Appropriate records documenting the medium, pressure, and duration of a test to substantiate MAOP should be kept for the life of the pipeline.

6 Corrosion Control

This section contains corrosion control and cathodic protection provisions for metallic Type C gathering lines.

6.1 External Corrosion Control for Buried or Submerged Pipelines

6.1.1 Cathodic Protection

6.1.1.1 General

A buried metallic pipeline shall have a cathodic protection system that is consistent with recognized and generally accepted industry practices, unless the operator demonstrates any of the following by tests, investigations, or experience:

- A corrosive environment does not exist,
- The pipe material is suitable for its design life without cathodic protection, or
- The installation of a cathodic protection system is impractical.

6.1.1.2 Test Stations

If a pipeline is under cathodic protection, the operator shall have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

6.1.1.3 Unprotected Pipelines

An operator shall evaluate a buried metallic pipeline that does not have a cathodic protection system at least once every 5 years and apply appropriate protective measures in areas where active corrosion is found.
6.1.1.4 Monitoring
A pipeline under cathodic protection shall be tested for adequate levels of cathodic protection at least once every 2 calendar years not to exceed 27 months.

6.1.1.4.1 A rectifier or other impressed current power source shall be inspected for proper operation at least four times each calendar year at intervals not exceeding three and a half months.

6.1.1.4.2 A reverse current switch, diode, and interference bond whose failure would jeopardize structure protection shall be electrically checked for proper performance at least four times each calendar year at intervals not exceeding three and a half months.

6.1.1.5 Remedial Action
An operator shall take remedial action to correct any deficiencies indicated by the monitoring performed in accordance with Section 6.1.1.4. The remedial actions shall be completed within a timeframe commensurate with the identified threat.

6.1.2 Coating
6.1.2.1 If cathodic protection is applied, a new metallic pipeline shall have an external protective coating.

6.1.2.2 If cathodic protection is applied, an operator shall protect external protective coating from damage resulting from adverse ditch conditions or damage from supporting blocks.

6.1.3 Electrical Isolation
6.1.3.1 A buried or submerged metallic pipeline should be electrically isolated where necessary to facilitate the application of corrosion control.

6.1.3.2 A cathodically protected pipeline should be electrically isolated from metallic casings that are part of an underground system where corrosion is a threat, unless other measures are taken to minimize corrosion of the pipeline inside the casing.

6.1.3.3 Inspection and electrical tests should be made to ensure that electrical isolation is adequate.

6.1.3.4 An isolation device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

6.1.3.5 Where a buried or submerged metallic pipeline is near electrical transmission tower footings, ground cables, or counterpoise, the pipeline should be protected against damage due to fault currents or lightning and protective measures should be taken at isolating devices.

6.1.4 Stray currents
If a pipeline is subjected to stray currents, the operator shall address the detrimental effects of such currents. An impressed current-type cathodic protection system or galvanic anode system shall be designed and installed to minimize any adverse effects on existing adjacent underground metallic structures.

6.2 Internal Corrosion Control
If a corrosive gas stream is transported in a buried metallic pipeline, the operator shall take steps to minimize corrosion or demonstrate that the level of corrosivity is acceptable. An operator should conduct monitoring to determine the effectiveness of the steps taken.

6.3 Atmospheric Corrosion Control
At least once every 3 calendar years, not to exceed 39 months, an operator shall inspect a pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion. If atmospheric corrosion is found that could affect the safe operation of the pipeline, the operator shall take appropriate remedial action.

6.4 Determining the Remaining Strength of Pipe
An operator may determine the strength of pipe based on actual remaining wall thickness in accordance with recognized and generally accepted industry practices. If the actual remaining wall thickness is insufficient to maintain the safe operation of the pipeline, the operator shall take appropriate remedial action.
6.5 Corrosion Control Records
An operator shall keep records documenting the adequacy of corrosion control measures for at least five years.

6.6 Implementation
The operator of a new pipeline should implement the provisions of Section 6 within 12 months of completion of construction. Unless the operator of an existing pipeline finds that a later implementation date is justified, the operator should implement the provisions of this section within 24 months of determining that the pipeline is a Type C gathering line.

7 Maximum Allowable Operating Pressure

7.1 The operating pressure shall not exceed the MAOP of the pipeline as determined in accordance with recognized and generally accepted industry practices.

7.2 For a new pipeline, the MAOP shall not exceed the lowest of the following pressures, as applicable:
   — The design pressure of the pipeline.
   — The test pressure of the pipeline.
   — The maximum safe pressure after considering the history of the pipeline, particularly known corrosion and the actual operating pressure.

7.3 For an existing pipeline, the maximum allowable operating pressure shall not exceed the lowest of the following pressures, as applicable:
   — The highest actual operating pressure that the pipeline experienced in the five years prior to implementation of this recommended practice unless the pipeline is tested to substantiate the maximum allowable operating pressure or is uprated to increase the previously established MAOP.
   — The maximum safe pressure after considering the history of the pipeline, particularly known corrosion and the actual operating pressure.

7.3.1 An operator should keep appropriate records documenting established MAOP for the life of the pipeline.

7.4 Uprating

7.4.1 The previously established MAOP of a pipeline may be increased if the operator implements a written procedure that meets the following conditions and is otherwise consistent with recognized and generally accepted industry practices.

7.4.1.1 The design, construction, testing, operation, and maintenance history of the pipeline is reviewed to determine if the higher MAOP is safe.

7.4.1.2 The pipeline is inspected for physical defects and operating conditions that could reasonably be expected to impair the integrity of the pipeline.

7.4.1.3 Any physical defects and operating conditions discovered during an inspection are repaired or corrected.

7.4.1.4 Records are available to demonstrate that the pipeline previously received an adequate test to a pressure greater than or equal to the higher MAOP.

7.4.1.5 If records are not available to demonstrate that the pipeline previously received an adequate test, the pressure of the pipeline is increased in appropriate increments to substantiate the higher MAOP, provided that appropriate action is taken after each incremental increase to detect and remediate leaks.

7.4.1.6 The higher MAOP does not exceed the MAOP permitted for a new line of the same design in the same location.
7.4.2 Appropriate records of any investigations, tests, repairs, replacements, and alterations performed in uprating the previously established MAOP of a pipeline should be kept for the life of the pipeline.

8 Operations and Maintenance

8.1 General
This section contains operations and maintenance provisions for new and existing pipelines.

8.2 Implementation

8.2.1 Existing Pipelines
An operator of an existing pipeline should develop and implement a program to comply with the operations and maintenance provisions in this section within 24 months of determining that the pipeline is a Type C.

8.2.2 New Pipelines
An operator of a new pipeline should develop and implement a program to comply with the operations and maintenance provisions of this section when the pipeline is placed into service.

8.2.3 General
An operator of a Type C Gathering Line shall carry out the requirements of section 5.1.1.

8.2.4 Damage Prevention Program
An operator shall participate in an applicable one-call system or damage prevention program.

8.2.5 Line Markers

8.2.5.1 Location
Buried pipelines shall have a line marker placed at the crossing of a public roadway, an active railway, or any other location deemed appropriate by the operator such as areas where there is a likelihood for damage.

8.2.5.2 Warning
A new or replaced line marker shall include a warning notifying the public about the presence of a gas pipeline, the operator’s name and a telephone number where the operator can be reached at all times.

8.2.5.3 Inspection
An operator shall inspect line markers where practicable during the performance of other field activities. If the inspection indicates that a line marker is missing or contains inaccurate information, appropriate remedial action should be taken.

8.2.5.4 Aboveground Installations
Markers or other signs may be placed at above-ground piping or facilities.

8.2.6 Public Awareness
An operator shall develop and implement a public awareness program to educate the public, emergency responders, and persons engaged in excavation-related activities on the essential elements identified in Section 8.2.6.1. Refer to API 1162 for further information on public awareness programs.

8.2.6.1 Essential Elements
A public awareness program shall include provisions that address the following topics:

— Use of a one-call notification system prior to excavation;
— Indications that a release of a gas from a pipeline may have occurred;
— Possible hazards associated with unintended releases of gas from a pipeline;
— Steps that can be taken to protect the public if gas is released from a pipeline; and
— Procedures for reporting an unintentional release of gas from a pipeline.

8.2.6.2 Local Knowledge

An operator may use local knowledge to identify the affected stakeholders covered in a public awareness program.

8.2.6.3 Operator Discretion

An operator may exercise discretion in determining the appropriate means of educating affected stakeholders, given local conditions.

8.2.7 Leak Surveys & Mitigation

8.2.7.1 Leak Survey

A leak survey shall be conducted at least once every three calendar years, not to exceed 39 months, or more frequently if deemed necessary by the operator based on local knowledge or leak history.

8.2.7.2 Leak Mitigation

An operator shall mitigate a leak that presents an immediate hazard to the public.

8.2.8 Emergency Response

An operator shall have a means for receiving notifications and responding to a pipeline emergency.

8.2.9 Repair

An operator shall make repairs in a safe manner in accordance with recognized and generally accepted industry practices.

9 Conversion to Service

9.1 Conversion

A pipeline previously used to transport a substance other than gas may be converted to use under this RP if the operator implements a written procedure that meets the following conditions and is otherwise consistent with recognized and generally accepted industry practices:

- The design, construction, operation, and maintenance history of the pipeline shall be reviewed and, where sufficient historical records are not available to demonstrate fitness, appropriate tests performed to determine if the pipeline is fit for service.
- The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments should be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.
- All known unsafe defects and conditions shall be corrected in accordance with this RP.

9.2 An operator shall keep appropriate records of any investigations, tests, repairs, replacements, or alterations performed as part of a conversion to service for the life of the pipeline.

10 Change of Service

10.1 If a Type D gathering line becomes a Type C gathering line, the operator should review their procedures with regards to the reclassified pipeline's Type C requirements.

Bibliography

AGA Standards

- AGA Catalog No. XR0603: Plastic Pipe Manual for Gas Service
• Gas Piping Technology Committee’s Guide Material Appendix G-192-15, Design of Uncased Pipeline Crossings of Highways and Railroads
• Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry

**API Standards**
• API Spec 5L: Specification for Line Pipe
• API RP 5L1, Recommended Practice for Railroad Transportation of Line Pipe
• API RP 5LW, Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels
• API RP 17B, Recommended Practice for Flexible Pipe
• API RP 500, Recommended Practices for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2
• API RP 1102, Steel Pipelines Crossing Railroads and Highways
• API RP 1110, Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide
• API Spec 6D, Specification for Pipeline and Piping Valves
• API Spec 17J, Specification for Unbonded Flexible Pipe
• API Std 1104, Welding of Pipelines and Related Facilities

**ASME Standards**
• ASME B31G, Manual for Determining the Remaining Strength of Corroded Pipelines: Supplement to ASME B31 Code for Pressure Piping
• ASME B31.3, Process Piping
• ASME B31.8S, Managing System Integrity of Gas Pipelines
• ASME BPV Code: Section II, Materials; Section VIII, Rules for Construction of Pressure Vessels; and Section IX, Qualification Standard for Welding, Brazing, and Fusing Procedures; Welders; Brazers; and Welding, Brazing, and Fusing Operators
• ASME PCC-2, including Supplement 1, Repair of Pressure Equipment and Piping

**ASTM Standards**
• ASTM A6/A6M, Standard Specification for General Requirements for Rolled Structural Steel Bars, Plates, Shapes, and Sheet Piling
• ASTM A20/A20M, Standard Specification for General Requirements for Steel Plates for Pressure Vessels
• ASTM A29/A29M, Standard Specification for Steel Bars, Carbon and Alloy, Hot-Wrought, General Requirements for
• ASTM A36/A36M, Standard Specification for Carbon Structural Steel
• ASTM A47/A47M, Standard Specification for Ferritic Malleable Iron Castings
• ASTM A48/A48M, Standard Specification for Gray Iron Castings
• ASTM A53/A53M, Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless
• ASTM A105/A105M, Standard Specification for Carbon Steel Forgings for Piping Applications
• ASTM A106/A106M, Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service
• ASTM A125, Standard Specification for Steel Springs, Helical, Heat-Treated
• ASTM A134, Standard Specification for Pipe, Steel, Electric-Fusion (Arc)-Welded (Sizes NPS 16 and Over)
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- ASTM A139/A139M, Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe (Sizes NPS 4 and Over)
- ASTM A181/A181M, Standard Specification for Carbon Steel Forgings, for General-Purpose Piping
- ASTM A182/A182M, Standard Specification for Forged or Rolled Alloy and Stainless-Steel Pipe Flanges, Forged Fittings, and Valves and Parts for High Temperature Service
- ASTM A193/A193M, Standard Specification for Alloy Steel and Stainless Steel Bolting Materials for High Temperature or High-Pressure Service and Other Special Purpose Applications
- ASTM A194/A194M, Standard Specification for Carbon and Alloy Steel Nuts for Bolts for High Pressure or High Temperature Service, or Both
- ASTM A197/A197M-00, Standard Specification for Cupola Malleable Iron
- ASTM A307, Standard Specification for Carbon Steel Bolts, Studs, and Threaded Rod 60 000 PSI Tensile Strength
- ASTM A320/A320M, Standard Specification for Alloy Steel and Stainless Steel Bolting for Low-Temperature Service
- ASTM A216/A216M, Standard Specification for Steel Castings, Carbon, Suitable for Fusion Welding, for High Temperature Service
- ASTM A217/A217M, Standard Specification for Steel Castings, Martensitic Stainless and Alloy, for Pressure Containing Parts, Suitable for High-Temperature Service
- ASTM A234/A234M, Standard Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and High-Temperature Service
- ASTM A242/A242M, Standard Specification for High Strength Low-Alloy Structural Steel
- ASTM A283/A283M, Standard Specification for Low and Intermediate Tensile Strength Carbon Steel Plates
- ASTM A354, Standard Specification for Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners
- ASTM A372/A372M, Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels
- ASTM A377, Standard Index of Specifications for Ductile-Iron Pressure Pipe
- ASTM A381, Standard Specification for Metal Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems
- ASTM A420/A420M, Standard Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Low-Temperature Service
- ASTM A487/A487M-4, Standard Specification for Steel Castings Suitable for Pressure Service
- ASTM A502, Standard Specification for Rivets, Steel, Structural
- ASTM A515/A515M, Standard Specification for Pressure Vessel Plates, Carbon Steel, for Intermediate and Higher-Temperature Service
- ASTM A516/A516M, Standard Specification for Pressure Vessel Plates, Carbon Steel, for Moderate and Lower-Temperature Service
- ASTM A575, Standard Specification for Steel Bars, Carbon, Merchant Quality, M-Grades
- ASTM A576, Standard Specification for Steel Bars, Carbon, Hot-Wrought, Special Quality
- ASTM A671/A671M, Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures
- ASTM A672/A672M, Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures
- ASTM A694/A694M, Standard Specification for Carbon and Alloy Steel Forgings for Pipe Flanges, Fittings, Valves and Parts for High-Pressure Transmission Service
- ASTM A1006/A1006M, Standard Specification for Steel Line Pipe, Black, Plain-End, Laser Beam Welded
- ASTM B21/B21M, Standard Specification for Naval Brass Rod, Bar, and Shapes
- ASTM B42, Standard Specification for Seamless Copper Pipe, Standard Sizes
- ASTM B61, Standard Specification for Steam or Valve Bronze Castings
- ASTM B62, Standard Specification for Composition Bronze or Ounce Metal Castings
- ASTM B66/B66M, Standard Specification for Seamless Copper Tube, Bright Annealed
- ASTM B75/B75M, Standard Specification for Seamless Copper Tube
- ASTM B88, Standard Specification for Seamless Copper Water Tube
- ASTM B249/B249M, Standard Specification for General Requirements for Wrought Copper and Copper Alloy Rod, Bar, Shapes, and Forgings
- ASTM B251, Standard Specification for General Requirements for Wrought Seamless Copper and Copper Alloy Tube
- ASTM B584, Standard Specification for Copper Alloy Sand Castings for General Applications
- ASTM D1598, Standard Test Method for Time-to-Failure of Plastic Pipe Under Constant Internal Pressure
- ASTM D2513, Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings
- ASTM D2517, Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings
- ASTM D2837, Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products
- ASME F1041, Standard Guide for Squeeze-Off of Polyethylene Gas Pressure Pipe and Tubing
- ASTM F1563, Standard Specification for Tools to Squeeze-Off Polyethylene (PE) Gas Pipe or Tubing
- ASTM F2817 Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair
- ASTM F2945 Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings

**CGA Standards**
- Best Practices Guide

**EPRI Standards**
- EPRI EL-3106 (also published as PRCI-AGA L51418, Power Line-Induced AC Potential on Natural Gas Pipelines for Complex Rights-of-Way Configurations)

**GPA Standards**
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- GPA Standard 2265-68, Determination of Hydrogen Sulfide and Mercaptan Sulfur in Natural Gas (Cadmium Sulfate Iodometric Titration Method)
- GPA Plant Operations Test Manual, Section C, Test for Hydrogen Sulfide in LPG and Gases (Tutweiler Method)

**GRI Standards**
- GRI-00/0154, Design Guide for Polyethylene Gas Pipes Across Bridges
- GRI-00/0192.01, GRI Guide for Locating and Using Pipeline Industry Research. Section 1: Fracture Propagation and Arrest
- GRI-00/0192.02, GRI Guide for Locating and Using Pipeline Industry Research. Section 2: Defect Assessment
- GRI-00/0192.03, GRI Guide for Locating and Using Pipeline Industry Research. Section 3: Identifying Types of Defects and Causes of Pipeline Failures
- GRI-00/0192.04, GRI Guide for Locating and Using Pipeline Industry Research. Section 4: Hydrostatic Testing
- GRI-00/0192.05, GRI Guide for Locating and Using Pipeline Industry Research. Section 5: Line Pipe
- GRI-00/0192.06, GRI Guide for Locating and Using Pipeline Industry Research. Section 6: Welding
- GRI-00/0192.07, GRI Guide for Locating and Using Pipeline Industry Research. Section 7: Fittings and Components
- GRI-00/0192.08, GRI Guide for Locating and Using Pipeline Industry Research. Section 8: Pipeline Repair Methods
- GRI-00/0192.09, GRI Guide for Locating and Using Pipeline Industry Research. Section 9: Mechanical Damage
- GRI-00/0192.10, GRI Guide for Locating and Using Pipeline Industry Research. Section 10: Corrosion
- GRI-00/0192.11, GRI Guide for Locating and Using Pipeline Industry Research. Section 11: Stress Corrosion Cracking
- GRI-00/0192.14, GRI Guide for Locating and Using Pipeline Industry Research. Section 14: In-Line Inspection
- GRI-00/0192.15, GRI Guide for Locating and Using Pipeline Industry Research. Section 15: Special Situations
- GRI-00/0192.16, GRI Guide for Locating and Using Pipeline Industry Research. Section 16: Risk Assessment
- GRI-00/0192.17, GRI Guide for Locating and Using Pipeline Industry Research. Section 17: Geographical Information Systems

**MSS Standards**
- MSS SP-6, Standard Finishes for Contact Faces of Pipe Flanges and Connecting-End Flanges of Valves and Fittings
- MSS SP-25, Standard Marking System for Valves, Fittings, Flanges, and Unions
- MSS SP-44, Steel Pipeline Flanges
- MSS SP-61, Pressure Testing of Valves
- MSS SP-70, Gray Iron Gate Valves, Flanged and Threaded Ends
- MSS SP-71, including Errata through February 2013, Gray Iron Swing Check Valves, Flanged and Threaded Ends
- MSS SP-75, High-Strength, Wrought, Butt-Welding Fittings
- MSS SP-78, Gray Iron Plug Valves, Flanged and Threaded Ends
- MSS SP-115 Excess Flow Valves, 1 ¼ NPS and Smaller, for Natural Gas Service

**NACE Standards**
- ANSI/NACE MR0175/ISO 15156, Petroleum and Natural Gas Industries — Materials for Use in H2S Containing Environments in Oil and Gas Production - Parts 1, 2, and 3
- NACE SP0169 Control of External Corrosion on Underground or Submerged Metallic Piping Systems
- NACE SP0177, Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems

**NFPA Standards**
- NFPA 30, Flammable and Combustible Liquids Code (including Errata 1)
- NFPA 70, National Electrical Code (including Amendments 1-8)
- NFPA 220, Standard on Types of Building Construction

**PPI Standards**
- Handbook of Polyethylene Pipe
- TR-3, Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe
- TR-4, Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Ratings For Thermoplastic Piping Materials or Pipe
- TR-33, Generic Butt Fusion Joining Procedure for Polyethylene Gas Pipe
- TR-41, Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping

**PRCI Standards**
- PRCI PR-185-9734 (PRCI Catalog L51782), Guidelines for Weld Deposition Repair on Pipelines
- PRCI PR-186-0324 (PRCI Catalog L52047), Updated Pipeline Repair Manual
- PRCI PR-218-05404 (PRCI Catalog L52314), Pipeline Defect Assessment — A Review and Comparison of Commonly Used Methods
- PRCI PR-218-9307 (PRCI Catalog L51716), Pipeline Repair Manual

**Other**
- Horizontal Directional Drilling — Good Practices Guidelines Publisher: HDD Consortium, available through North American Society for Trenchless Technology (NASTT), 7745 Morgan Road, Liverpool, NY 13090 ([www.nastt.org](http://www.nastt.org))
- PRCI PR-227-03110, Installation of Pipelines Using Horizontal Directional Drilling, — An Engineering Design Guide. Publisher: Pipeline Research Council International (PRCI), 3141 Fairview Park Drive, Falls Church, VA 22042 ([www.prci.org](http://www.prci.org))