



VIA ELECTRONIC FILING

April 6, 2020

Docket Management Facility
U.S. Department of Transportation
1200 New Jersey Ave, S.E.
Washington, D.C. 20590

Re: Docket No. PHMSA-2013-0255, Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards

To Whom It May Concern:

On February 6, 2020, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published a notice of proposed rulemaking (NPRM) in the *Federal Register* in the above-captioned proceeding.¹ The NPRM contained proposed valve installation and minimum rupture detection standards for operators of gas, hazardous liquid, and carbon dioxide pipelines. PHMSA asked that any interested parties submit written comments in response to the NPRM by no later than April 6, 2020.

I. Introduction

GPA Midstream Association (GPA Midstream) is submitting these comments on behalf of its member companies.² GPA Midstream shares PHMSA's interest in promoting the safe and effective transportation of the nation's energy products but is concerned by various aspects of the NPRM. These concerns are briefly summarized below and discussed in more detail in the rest of this letter.

¹ Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards, 85 Fed. Reg. 7,162 (Feb. 6, 2020) (hereinafter "NPRM").

² GPA Midstream 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. See <https://gpaglobal.org/>.

A. Cost-Benefit Analysis

The Preliminary Regulatory Impact Analysis (PRIA) for the NPRM dramatically understates the potential costs of the proposed valve installation and rupture detection standards. PHMSA estimates that the annual costs of implementing the proposed rules will be approximately \$3.1 million, calculated using a 7 percent discount rate. However, an estimate prepared several decades ago showed that the cost of complying with similar valve installation standards would exceed \$600 million. The PRIA offers no explanation for the significant discrepancy between these two cost estimates and fails in several other respects to satisfy the requirements in the Pipeline Safety Act. The inadequacy of the PRIA is particularly impactful given the extraordinary economic conditions currently confronting the oil and gas industry throughout the United States.

B. Proposed Rules

With regard to the substance of the NPRM, the proposed rules can be significantly improved in the following respects:

- *Consolidating or Eliminating Unnecessary Language, Criteria, and Requirements.* The same language, criteria, and requirements are unnecessarily restated in numerous sections of the NPRM. To the maximum extent possible, PHMSA should consolidate duplicative provisions and include appropriate cross-references. Several unnecessary provisions can also be eliminated. Making these changes will improve the organization, structure, and clarity of the new regulations and facilitate operator compliance.
- *Modifying the Definition of Rupture and Adding Definitions for Rupture Identification and Rupture Mitigation Valves.* Rather than using the unworkable criteria proposed in the NPRM, PHMSA should establish a definition of “rupture” that incorporates the concepts used in the incident and accident reporting forms. PHMSA should also add definitions for “rupture identification” and “rupture mitigation valve.” Defining these key terms will improve the clarity of the new regulations and facilitate operator compliance.
- *Limiting Applicability of Valve Installation and Location Requirements to Pipeline Replacements.* The rupture mitigation valve installation requirements should only apply to pipeline replacements involving 2 or more contiguous miles of pipe, and the other valve installation and location requirements should only apply to pipeline replacements involving more than 2,000 contiguous feet of pipe. Adding these limitations will ensure that the new regulations do not impose unreasonable compliance burdens on pipeline operators.
- *Exceptions for Gathering Lines.* An exception from the rupture mitigation valve installation requirements must be provided for gathering lines. The statutory mandate addressed in the NPRM only applies to transmission pipeline facilities, and there is no indication that Congress intended to require the installation of rupture mitigation valves on gathering lines. Most gathering lines present a very low risk to public safety and are regulated on a segment-by-segment basis. Requiring gathering line operators to install rupture mitigation valves is not economically, technically, or operationally feasible.

- *Limiting Applicability of Rupture Mitigation Valve Installation to Higher-Risk Pipeline Segments.* The rupture mitigation valve installation requirements should only apply to larger diameter, high-stress pipeline segments in higher-risk locations. Limiting the rupture mitigation valve installation requirements to these higher-risk pipeline segments will create the greatest benefit to public safety without imposing unreasonable compliance burdens on the regulated community. PHMSA should also clarify the process for obtaining authorization to install manual valves or use equivalent technologies in the new regulations.
- *Establishing Class-Location-Related Valve Installation Requirements.* Specific valve installation requirements should be added for class-location-related pipeline replacements. Under PHMSA’s interpretation of the current regulations, operators must comply with valve installation requirements for new pipelines if a segment is replaced in response to a class location change. That interpretation is contrary to the original intent of the regulations, imposes unreasonable compliance burdens, and discourages pipeline replacements. PHMSA should establish more reasonable valve installation requirements for class-location-related pipeline replacements in the new regulations.
- *Clarifying Valve Location Requirements.* The proposed maximum valve spacing intervals for highly volatile liquid (HVL) pipelines, high consequence area (HCA) pipelines, and non-HCA pipelines should be consolidated into a single provision, and changes should be made to align with comparable Canadian standards. Some of the other proposals in the NPRM are unnecessary or lack an adequate technical justification and should be eliminated.
- *Clarifying the Operations, Maintenance, and Integrity Management Requirements.* The changes to the operations, maintenance, and integrity management requirements should be modified to eliminate unnecessary provisions, provide greater clarity, and facilitate operator compliance.

II. Background

In Section 4 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act),³ Congress directed PHMSA to establish regulations, if appropriate, requiring the use of automatic shutoff valves (ASVs), remote-control valves (RCVs), “or equivalent technology, where economically, technically, and operationally feasible on transmission pipeline facilities constructed or entirely replaced after the [effective date of those regulations].”⁴ Congress ordered PHMSA to consider many of the same factors that apply in prescribing other pipeline safety standards as part of the rulemaking mandate.⁵ To determine the economic, technical, and operational feasibility of installing ASVs or RCVs, Congress also required the Comptroller General to prepare a study on the ability of pipeline operators to respond to a gas or hazardous

³ Pub. L. 112-90 § 4 (Jan. 3, 2012), 125 Stat. 1904, 1907.

⁴ 49 U.S.C. § 60102(n)(1) (2018).

⁵ See *id.* at § 60102(b)(2) (requiring consideration of, among other things, “the appropriateness of the standard for the particular type of pipeline transportation or facility,” “the reasonableness of the standard,” and “the reasonably identifiable or estimated costs expected to result from implementation or compliance with the standard”).

liquid release from a pipeline segment in an HCA.⁶ In preparing that study, Congress directed the Comptroller General to consider certain specific factors, including “the swiftness of leak detection and pipeline shutdown capabilities, the location of the nearest response personnel, and the costs, risks, and benefits of installing [ASVs or RCVs].”⁷ The Government Accountability Office (GAO) published the results of the Comptroller General’s study in a 2013 report,⁸ and PHMSA acknowledged its obligation to consider the GAO report in preparing the NPRM.⁹

In February 2020, PHMSA published the NPRM under consideration in this proceeding. Citing certain recent pipeline incidents and the rulemaking mandate in Section 4 of the 2011 Act, PHMSA proposed new valve installation and minimum rupture detections standards for gas, hazardous liquid, and carbon dioxide pipelines, including significant changes to the definitions, design, construction, operations, maintenance, and integrity management requirements.¹⁰ PHMSA also released a PRIA for the NPRM, estimating that the annual implementation costs would be approximately \$3.1 million, calculated using a 7 percent discount rate.¹¹ PHMSA provided a 60-day period for submitting comments on the NPRM, and recently indicated that the Liquid Pipeline Advisory Committee (LPAC) and Gas Pipeline Advisory Committee (GPAC) would be meeting to consider the proposed rules in a joint session on July 22 to 23, 2020.

III. The PRIA Significantly Underestimates the Cost of the NPRM and Does Not Account for the Extraordinary Economic Circumstances that the Pipeline Industry is Experiencing.

The Pipeline Safety Act generally requires PHMSA to prepare a risk assessment quantifying the benefits and costs of new pipeline safety standards,¹² and to consider “the reasonably identifiable or estimated benefits [and costs] expected to result from implementation or compliance with the standard[,]” as well as the “comments and information received from the public” during the rulemaking process.¹³ Section 4 of the 2011 Act also requires PHMSA to consider the economic feasibility of installing ASVs or RCVs on transmission pipeline facilities as part of the rulemaking process.¹⁴ PHMSA’s failure to prepare an adequate risk assessment, or to properly consider the costs, benefits, and related public comments submitted in response to the NPRM, provides grounds for challenging the validity of the final rule.¹⁵

⁶ *Id.* at § 60102(n)(2)(A).

⁷ *Id.* at § 60102(n)(2)(B).

⁸ U.S. Gov’t Accountability Office, GAO-13-168, Report to Congressional Committees, Pipeline Safety: Better Data and Guidance Needed to Improve Pipeline Operator Incident Response (Jan. 2013), <https://www.gao.gov/assets/660/651408.pdf> (hereinafter “GAO Report”).

⁹ NPRM at 7,163.

¹⁰ *Id.* at 7,162.

¹¹ Preliminary Regulatory Impact Analysis, Amendments to Parts 192 and 195 to Require Valve Installation and Minimum Rupture Detection Standards Proposed Rule (Feb. 2020), <https://www.regulations.gov/document?D=PHMSA-2013-0255-0006> (hereinafter “PRIA”).

¹² 49 U.S.C. §§ 60102(b)(2)(D)-(E), (3)-(6).

¹³ *Id.* § 60102(b)(2)(D)-(F).

¹⁴ *Id.* § 60102(n)(1).

¹⁵ *Motor Vehicle Mfrs. Ass’n of U.S. v. State Farm Mutual Automobile Ins. Co.*, 463 U.S. 29, 43 (1983) (“Normally, an agency rule would be arbitrary and capricious if the agency . . . entirely failed to consider an important aspect of the problem . . .”); *Carlson v. Postal Regulatory Comm’n*, 938 F.3d 337, 344 (D.C. Cir. 2019) (“An agency also

PHMSA estimates that the annualized costs of the proposed valve installation and rupture detection standards, using a 7 percent discount rate, would be \$1.2 million for natural gas operators and \$1.9 million for hazardous liquid operators (\$3.1 million in total) in the PRIA.¹⁶ Other assessments show that PHMSA's cost estimate dramatically underestimates the economic impact of the proposed rules. Industry data submitted to PHMSA's predecessor in 1989 estimated that the costs for converting mainline manual valves to ASVs would be \$610 million and RCVs would be \$680 million.¹⁷ The PRIA does not provide an adequate explanation for the significant discrepancy between these cost two estimates.

The energy industry is also experiencing significant economic hardship due to the COVID-19 pandemic, which is adversely affecting global markets. At the same time, the industry is facing a concerted effort by certain foreign countries to flood the international market with crude oil, which is creating equally dramatic changes in energy markets. The PRIA does not account for the near-term or long-term impact of these extraordinary economic conditions. To meet its statutory obligations, PHMSA must address the deficiencies in the PRIA in analyzing the costs and benefits of any potential changes to the valve installation and rupture detection standards.

GPA Midstream reminds PHMSA of the critical function that the GPAC and LPAC serve in reviewing "the technical feasibility, reasonableness, cost-effectiveness, and practicability" of proposed rules under the Pipeline Safety Act.¹⁸ GPA Midstream also reminds PHMSA of the separate obligation that the GPAC and LPAC have to specifically review the PRIA, including "an evaluation of the merit of the data and methods used" and "any recommended options relating to [the] risk assessment information and the associated standard that the committee determines to be appropriate".¹⁹ GPA Midstream expects PHMSA to use the authority provided in the Pipeline Safety Act and respective committee charters to ensure that the GPAC and LPAC meet these statutory obligations as part of the rulemaking process.

IV. The Definition of Rupture Should Be Simplified and New Definitions for Rupture Identification and Rupture Mitigation Valve Should Be Added.

A. Comments

In the NPRM, PHMSA proposes to add definitions for the term "rupture" in 49 C.F.R. § 192.3 and § 195.2.²⁰ The proposed definitions contain impractical criteria, including volumetric thresholds that lack any technical justification, and focus too heavily on the sources of information that an operator might use to identify a rupture, rather than setting reasonable parameters for what

violates [the arbitrary and capricious] standard if it fails to respond to 'significant points' and consider 'all relevant factors' raised by the public comments" (*citing Home Box Office, Inc. v. FCC*, 567 F.2d 9, 35-36 (D.C. Cir. 1977)).

¹⁶ PRIA at 8.

¹⁷ Dep't of Transp., Safety Review Task Force, Report on the Research and Special Program Administration's Pipeline Safety Program at 13-14 (January 1989).

¹⁸ 49 U.S.C. § 60115(c)(2).

¹⁹ *Id.* § 60102(b)(4)(B). The risk assessment is a document that describes "the reasonably identifiable or estimated [costs and] benefits expected to result from implementation or compliance with the standard." *Id.* § 60102 (b)(2)(D)-(E), (3).

²⁰ NPRM at 7,182, 7,186.

constitutes a rupture. PHMSA also fails to define at least two other key terms in the NPRM, *i.e.*, “rupture identification” and “rupture mitigation valve”. The absence of these definitions makes the subsequent provisions for rupture mitigation valves unnecessarily long, complex, and confusing.

PHMSA’s proposed definition of rupture incorporates numerical thresholds for pressure loss and flow rate that would encompass many non-rupture scenarios (e.g., power loss at a pump station).²¹ PHMSA does not provide any technical justification for these numeric thresholds in the NPRM, and rigid application of the criteria, such as a 10% flow rate change or pressure loss, will lead to numerous false alarms and unnecessary valve closures. As the Comptroller General acknowledged in the GAO report, unplanned valve closures can lead to a loss of service or even rupture the pipeline.²² Rules that are intended to mitigate pipeline ruptures should not rely on a definition that may actually lead to those events.

Adopting a simpler definition of “rupture” will alleviate many of these concerns. Rather than using the criteria proposed in the NPRM, PHMSA should define “rupture” based on the guidance provided in the instructions for the Part 192 and Part 195 reporting requirements, *i.e.*, a rupture is the bursting, breaking, or splitting of a pipeline that immediately impairs its operation and results in an uncontrolled, large volume release of gas, hazardous liquid, or carbon dioxide.²³ Unlike the NPRM, the reporting instructions do not rely on impractical numerical thresholds or sweeping catch-all provisions in defining a “rupture”—operators are allowed to exercise reasonable judgment in determining whether an event meets the applicable criteria.²⁴ The guidance provided in the instructions for the Part 192 and Part 195 reporting requirements has been in place for nearly a decade, and there is no need to adopt a different definition.²⁵ Following the approach laid out in the reporting instructions will promote consistency, make the regulations easier to understand, and avoid unnecessary compliance burdens.

PHMSA should also add a separate definition for “rupture identification” to improve the clarity of the regulations. As with other similar provisions in Part 192 and Part 195, that definition

²¹ *Id.*

²² GAO Report at 24 (“For hazardous liquid pipelines, accidental closures can cause an incident, when a valve closes and the subsequent pressure buildup causes the pipeline to rupture.”).

²³ Instructions (rev 4-2019) for Form PHMSA F 7100.2 (Rev 4-2019) Incident Report – Gas Transmission And Gathering Systems at 19, <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/subdoc/3971/currentgtggincidentinstructionsphmsa-f-710022019-04-and-beyond.pdf>; Instructions (rev 12-2015) for Form PHMSA F 7000-1 (rev 7-2014) Accident Report – Hazardous Liquid Pipeline Systems at 15, <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/subdoc/3231/currenthlaccidentinstructionsphmsa-f-7000-112-2015-and-beyond.pdf>. *See also* 49 C.F.R. § 191.3 (2019) (definition of incident).

²⁴ Instructions (rev 4-2019) for Form PHMSA F 7100.2 (Rev 4-2019) Incident Report – Gas Transmission And Gathering Systems at 19; Instructions (rev 12-2015) for Form PHMSA F 7000-1 (rev 7-2014) Accident Report – Hazardous Liquid Pipeline Systems at 15

²⁵ *See* Instructions For Form PHMSA F 7100.2 (Rev. 06-2011) Incident Report – Natural And Other Gas Transmission And Gathering Pipeline Systems at 18, <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/subdoc/3201/gtggincidentinstructionsphmsa-f-710022010-through-2011.pdf>; Instructions For Form PHMSA F 7000.1 (Rev. 12-2012) Accident Report – Hazardous Liquid Pipeline Systems at 16, <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/subdoc/3241/hlaccidentinstructionsphmsa-f-7000-1revised-12-2012.pdf>.

should adopt a reasonableness standard, *i.e.*, rupture identification occurs when a pipeline operator has sufficient information to reasonably determine that a rupture occurred.²⁶ There is no need to provide an expansive list of the information that an operator needs to consider in determining if a rupture occurred, which simply results in an unnecessarily long provision that fails to provide any additional meaningful guidance. PHMSA should adopt a clear and succinct definition for “rupture identification” that relies on a reasonable standard.

PHMSA should add a definition of “rupture mitigation valve” as well. The definition should identify the two types of qualifying valves, *i.e.*, ASVs and RCVs, and purpose served by these valves, *i.e.*, minimizing the volume of gas, hazardous liquid, or carbon dioxide released from a pipeline and mitigating the safety and environmental consequences of a rupture. The definition should not refer to manual valves or equivalent technology, which can only be installed or used as an alternative to rupture mitigation valves if the operator satisfies certain requirements in the subsequent regulations. For hazardous liquid and carbon dioxide pipelines, check valves should be included as ASVs in the definition. That position is consistent with the analysis in the 2013 GAO report, which treats check valves as automated valves.²⁷

B. Proposed Regulatory Language

§192.3 Definitions.

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Rupture means the bursting, breaking, or splitting of a pipeline that immediately impairs its operation and results in an uncontrolled, large volume release of gas.

Rupture identification means that a pipeline operator has sufficient information to reasonably determine that a rupture occurred.

Rupture mitigation valve means an automatic shut-off valve or a remote-control valve that a pipeline operator uses to minimize the volume of gas released and mitigate the safety and environmental consequences of a rupture.

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²⁶ 49 C.F.R. § 191.3, (defining confirmed discovery for purposes of the incident reporting requirements as “when it can be reasonably determined based on information available to the operator at the time the reportable event has occurred”), § 195.2 (defining confirmed discovery for purposes of the accident reporting requirements); § 192.933(b) (defining discovery of a condition for purposes of addressing integrity issues as “when an operator has adequate information about a condition to determine” it presents a potential integrity threat).

²⁷ GAO Report at 11, n.15 (“Hazardous liquid regulations refer to emergency flow restriction devices, which include remote-control valves and ‘check’ valves that automatically prevent product from flowing in a specific direction. See 49 C.F.R. § 195.452(i)(4). For the purposes of this report we describe all of these valves as automated valves[.]”).

§195.2 Definitions.

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Rupture means the bursting, breaking, or splitting of a pipeline that immediately impairs its operation and results in an uncontrolled, large volume release of hazardous liquid or carbon dioxide.

Rupture identification means that a pipeline operator has sufficient information to reasonably determine that a rupture occurred.

Rupture mitigation valve means an automatic shut-off valve (including a check valve) or a remote-control valve that a pipeline operator uses to minimize the volume of hazardous liquid or carbon dioxide released and mitigate the safety and environmental consequences of a rupture.

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V. The Applicability of the Valve Installation Requirements Should Be Limited to Pipeline Replacements Involving More Than 2,000 Feet of Contiguous Pipe.

A. Comments

PHMSA's position is that the valve installation requirements in Part 192 and Part 195 currently apply to all pipeline replacements without regard to length.²⁸ In other words, a gas transmission line operator that replaces 10 feet of pipe must install whatever valves are necessary to comply with the spacing requirements in § 192.179, and a regulated gathering line operator that replaces 10 feet of pipe must comply with the same valve installation requirements under §§ 192.9(c) and (d)(1). A hazardous liquid or carbon dioxide pipeline operator that replaces 10 feet of pipe must comply with the valve installation and location requirements in §§ 195.258 and 195.260 as well.

Applying the valve installation requirements for new pipelines to all pipeline replacements is unnecessary and impractical. There is no indication that requiring operators to install additional valves in these circumstances produces meaningful benefits to public safety, particularly for short-length pipeline replacements. Mandating compliance with the valve installation requirements in all cases may actually reduce public safety by encouraging operators to defer certain voluntary replacements. PHMSA's regulations should not create these kinds of irrational incentives.

The valve installation requirements should only apply to significant pipeline replacements, or those that involve more than 2,000 feet of contiguous pipe.²⁹ Prior PHMSA enforcement history indicates that replacements over the 2,000-foot threshold are significant enough to justify compliance with the valve installation requirements for new pipelines.³⁰ PHMSA should add an

²⁸ NPRM at 7,182, 7,186.

²⁹ The 2,000 foot threshold proposed by GPA Midstream is based off of the amount of pipe replaced in *In the Matter of Viking Gas Transmission*, Final Order, CPF No. 32102 (May 1, 1998). See also NPRM at 7,168–69.

³⁰ See NPRM at 7,169.

exception to that effect to the general applicability provision in § 192.13(b) for gas pipelines and the provision in § 195.200 that establishes the scope of the construction requirements for hazardous liquid and carbon dioxide pipelines, starting as of the effective date of the final rule.

In the NPRM, PHMSA proposed to limit the rupture mitigation valve installation requirements to replacements of 2 or more miles of contiguous pipe, and that limitation should be added to § 192.13(b) for gas pipelines and § 195.200 for hazardous liquid and carbon dioxide pipelines as well. PHMSA also proposed to make the rupture mitigation valve installation requirements effective 12 months after the effective date of the final rule.³¹ However, a 12-month deadline does not provide operators with sufficient time to facilitate compliance. Operators will need to acquire additional property, obtain new permits and authorizations, acquire valves and equipment, and take other actions to install rupture mitigation valves. PHMSA should make the rupture mitigation valve installation requirements effective 24 months after the effective date of the final rule to account for these activities.

As proposed in the NPRM, the maximum valve spacing intervals in § 195.260 should only to pipeline replacements that meet the 2-mile threshold.. An exception to that effect should be added in § 195.200 to improve the clarity of the new regulations. Note that the language proposed below incorporates references to other changes to the valve requirements in §§ 192.179, 192.258, and 195.260 that are discussed in subsequent parts of these comments.

B. Proposed Regulatory Language

§192.13 What general requirements apply to pipelines regulated under this part?

(a) * * * * *

(b) No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation or change has been made according to the requirements in this part, **except that:**

(1) The valve installation requirements in § 192.179(a)-(d) and § 192.611(e) only apply if more than 2,000 contiguous feet of pipe is replaced in an existing pipeline system after [EFFECTIVE DATE OF FINAL RULE]; and

(2) The rupture mitigation valve installation requirements in § 192.179(e)-(g) only apply if 2 or more miles of contiguous pipe is replaced in an existing pipeline system after [24 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE].

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³¹ *Id.* at 7,184, 7,187.

§195.200 Scope.

This subpart prescribes minimum requirements for constructing new pipeline systems with steel pipe, and for relocating, replacing, or otherwise changing existing pipeline systems that are constructed with steel pipe. However:

(a) This subpart does not apply to the movement of pipe covered by §195.424;

(b) The valve location requirements in §§ 195.258(a)-(b) and 195.260(a)-(f) only apply to new pipeline systems, or replacements of more than 2,000 contiguous feet of pipe in an existing pipeline system, after [EFFECTIVE DATE OF FINAL RULE]; and

(c) The rupture mitigation valve installation requirements in § 195.258(c)-(e) and maximum valve spacing intervals in § 195.260(g) only apply to new pipeline systems, or replacements of 2 or more contiguous miles of pipe in an existing pipeline system, after [24 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE].

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VI. The Rupture Mitigation Valve Installation Requirements Should Not Apply to Gathering Lines.

A. Comments

In the NPRM, PHMSA proposed to require the installation of rupture mitigation valves on onshore pipelines 6 inches or greater in diameter that are constructed or meet the 2-mile replacement threshold starting 12 months after the effective date of the final rule.³² Although the rulemaking mandate in Section 4 of the 2011 Act is limited to transmission pipeline facilities, PHMSA's proposed rules would apply to certain regulated gathering lines.³³ There is no indication that Congress intended to require the installation of rupture mitigation valves on gathering lines, or that doing so would be economically, technically, and operationally feasible.

Because PHMSA's regulations only apply to onshore gathering lines that meet certain risk-based criteria,³⁴ the length of regulated gathering line segments varies considerably depending on the location and operating characteristics of a system. Part 192 may only apply to the portion of an operator's onshore gas gathering line that passes through an isolated, Class 3 location, or to specific class location units that have more than 10 buildings intended for human occupancy. Likewise, Part 195 may only apply to the portion of an operator's petroleum gathering lines that briefly passes through the boundaries of a non-rural area or within a ¼ mile of an unusually

³² NPRM at 7,183–84, 7,187–88.

³³ 49 U.S.C. § 60102(n).

³⁴ Part 192 only applies to onshore gas gathering lines in more populated Class 2, Class 3, or Class 4 locations. 49 C.F.R. §§ 192.8, 192.9. Part 195 only applies to gathering lines in non-rural areas and gathering lines in rural areas that have a nominal diameter from 6 5/8 to inches to 8 5/8 inches, are located within 0.25 miles of an unusually sensitive area, and operate at a maximum operating pressure corresponding to a stress level greater than 20 percent of the specified minimum yield strength of the line pipe or 125 psig. *Id.* § 195.11(a).

sensitive area. The total length of the regulated gathering line segment is very short in these scenarios.

Requiring operators of regulated onshore gathering lines to comply with the rupture mitigation installation requirements is unnecessary and impractical. The segmented nature of the Part 192 and Part 195 rules for gathering lines would create significant compliance challenges for operators, both at the time of installation and in the event of subsequent replacements. Operators would need to install rupture mitigation valves on unregulated segments to protect regulated segments that may only extend a very short distance. As important, Congress specifically limited the rulemaking mandate in Section 4 of the 2011 Act to transmission pipeline facilities.³⁵ While PHMSA often applies the requirements for transmission pipelines to certain regulated gathering lines,³⁶ there is no indication that Congress intended PHMSA to use that interpretation in applying the rulemaking mandate for the installation of ASVs and RCVs.

Nor has PHMSA produced any data demonstrating that the installation of rupture mitigation valves on regulated gathering lines is technically, economically, or operationally feasible, or will produce the kind of meaningful public safety benefits needed to justify the resulting costs. Gathering lines present a very low risk to public safety, and PHMSA has recently acknowledged in other rulemaking proceedings that the Agency lacks the comprehensive safety data needed to properly evaluate the feasibility of installing rupture mitigation valves on gathering lines. Accordingly, an exception from that requirement should be added to §§ 192.9(c) and (d) for regulated onshore gas gathering lines and § 195.258(c) for regulated petroleum lines in rural and non-rural areas.

B. Proposed Regulatory Language

§192.9 What requirements apply to gathering lines?

(a) *Requirements.* An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.150, 192.179(e)-(g), and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.150, 192.179(e)-(g), and in subpart O of this part. However, an operator of a Type A 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.

(d) *Type B lines.* An operator of a Type B regulated onshore gathering line must comply with the following requirements:

³⁵ 49 U.S.C. § 60102(n).

³⁶ 49 C.F.R. § 192.9.

(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 for § 192.179(e)-(g);**

* * * * *

§ 195.258 Valves: General.

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(c) **Except for pipelines in offshore locations and gathering lines, each pipeline segment that is:**

* * * * *

VII. The Rupture Mitigation Valve Requirements Should Only Apply to Higher Stress Pipeline Segments in Higher Risk Locations.

A. Comments

In the NPRM, PHMSA proposed to limit the rupture mitigation valve installation requirements to pipelines 6 inches or greater in diameter.³⁷ While pipe diameter is one of the factors that may be relevant in determining risk, stress level is a far better indicator of whether a pipeline will rupture during operation. Pipelines with a maximum allowable operating pressure (MAOP) or maximum operating pressure (MOP) that produces a stress level of 30 percent of specified minimum yield strength (SMYS) or less are only likely to leak, not rupture. As PHMSA notes in the NPRM, the rupture mitigation valve installation requirements are intended to mitigate the latter events. Therefore, the requirements should only apply to high-stress pipelines with MAOPs or MOPs greater than 30 percent of SMYS.

The potential consequences of a rupture are another factor that should be considered in applying the rupture mitigation valve installation requirements. PHMSA's regulations already recognize well-established mechanisms for representing the potential consequences of a pipeline rupture. The Part 192 regulations use HCAs, which depending on the method used include Class 3 and Class 4 locations or areas where the potential impact circle contains a certain number of buildings intended for human occupancy or identified sites, to delineate locations that present a higher risk to public safety.³⁸ The Part 195 regulations also use HCAs, which include commercially navigable waterways, high population areas, other populated areas, and unusually sensitive areas.³⁹ Installing rupture mitigation valves to protect these higher-risk locations will

³⁷ NPRM at 7,183, 7,187–88. And, in Footnote 7 of the NPRM characterizes the 6-inch diameter threshold as a measurement of the approximate inner diameter of the pipe with a non-dimensional number. *Id.* at 7,164 n.7. For purposes of clarity, PHMSA should instead refer to this threshold in terms of outside diameter, as used elsewhere in Part 195. A 6.625-inch outside diameter threshold is equivalent to a 6-inch nominal diameter threshold. ANSI B36.10-1979, Welded and Seamless Wrought Steel Pipe at 1075 (1979).

³⁸ 49 C.F.R. § 192.903.

³⁹ *Id.* § 195.450.

provide the greatest benefit to public safety without imposing unnecessary compliance costs or other undue burdens on operators. Note that the rupture mitigation valve installation requirements would be limited to replacements of 2 or more miles of contiguous pipe in existing pipeline systems, starting 24 months after the effective date of the final rule, as a result of the exceptions in § 192.13 and § 195.200 discussed earlier in these comments.⁴⁰

Finally, the language authorizing the installation of manual valves or use of equivalent technology should be restructured to provide greater clarity. The NPRM uses unnecessarily repetitive language and creates ambiguity about the status of equivalent or alternative technologies. PHMSA should lay out the process for installing manual valves or using equivalent technologies directly in the rupture mitigation valve installation requirements. PHMSA should also specify the timing (at least 90 days in advance), content, and process for submitting the initial notification and provide for a one-time extension of the initial review period (not more than 45 days) to facilitate expeditious agency action. PHMSA should state that an operator is authorized to install a manual valve or use an equivalent technology if a letter of objection is not received within the applicable time period.

B. Proposed Regulatory Language

§192.179 Transmission line valves.

* * * * *

(e) An onshore transmission line segment that:

(i) is placed into service after [DATE 24 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE];

(ii) is constructed with pipe 6.625 inches or greater in outside diameter;

(iii) has a maximum allowable operating pressure that produces a hoop stress greater than 30 percent of SMYS; and

(iv) is in a Class 3 or Class 4 location or a high consequence area

must be installed with rupture mitigation valves spaced at the intervals provided in paragraph (a), unless the installation of a manual valve or the use of an equivalent technology is permitted under paragraphs (f) and (g).

(f) To install a manual valve or use an equivalent technology under paragraph (e) of this section, an operator must:

(1) Send a notification to PHMSA at least 90 days prior to the proposed installation or use by:

⁴⁰ See *supra* Section V.

(i) electronic mail to InformationResourcesManager@dot.gov; or

(ii) mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave SE., Washington, DC 20590; and

(2) Provide the information necessary to demonstrate that:

(i) The installation of a rupture mitigation valve is economically, technically, or operationally infeasible; and

(ii) The manual valve or equivalent technology can be operated and maintained in accordance with the requirements in §§ 192.634 and 192.745.

(g) The installation of a manual valve or use of an equivalent technology is authorized 91 days after PHMSA receives the notification required under paragraph (d) of this section, unless the operator receives a letter from the Associate Administrator for Pipeline Safety objecting to the proposed installation or use or indicating that an additional time period not to exceed 45 days is needed to complete the review. The installation of a manual valve or use of an equivalent technology is authorized after the expiration of the additional 45-day review period, unless the operator receives another letter from the Associate Administrator for Pipeline Safety objecting to the proposed installation or use.

§ 195.258 Valves: General.

* * * * *

(c) Except for pipelines in offshore locations and gathering lines, a pipeline segment that is:

(1) Placed into service after [DATE 24 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE];

(2) Constructed with steel pipe 6.625 inches or greater in outside diameter;

(3) has a maximum operating pressure under § 195.406 that produces a stress level greater than 30 percent of the specified minimum yield strength of the line pipe; and

(4) is in a location that could affect a high consequence area

must have rupture mitigation valves installed in accordance with the requirements of § 195.260, unless the installation of a manual valve or use of an equivalent technology is authorized under paragraphs (d) and (e) of this section.

(d) To install a manual valve or use an equivalent technology under paragraph (c) of this section, an operator must:

(1) Send a notification to PHMSA at least 90 days prior to the proposed installation or use by:

(i) electronic mail to InformationResourcesManager@dot.gov; or

(ii) mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave SE., Washington, DC 20590; and

(2) Provide the information necessary to demonstrate that:

(i) The installation of a rupture mitigation valve is economically, technically, or operationally infeasible; and

(ii) The manual valve or equivalent technology can be operated and maintained in accordance with the requirements in §§ 195.418 and 195.420.

(e) The installation of a manual valve or use of an equivalent technology is authorized 91 days after PHMSA receives the notification required under paragraph (d) of this section, unless the operator receives a letter from the Associate Administrator for Pipeline Safety objecting to the proposed installation or use or indicating that an additional time period not to exceed 45 days is needed to complete the review. The installation of a manual valve or use of an equivalent technology is authorized after the expiration of the additional 45-day review period, unless the operator receives a letter from the Associate Administrator for Pipeline Safety objecting to the proposed installation or use.

VIII. PHMSA Should Establish Specific Valve Installation Requirements for Class-Location-Related Pipeline Replacements in § 192.611.

A. Comments

PHMSA states in the NPRM that the valve installation requirements for new pipelines apply to all pipeline replacements that respond to class location changes and proposes to codify that position in a new regulation, § 192.610.⁴¹ Although PHMSA points to a recent enforcement action to support that position, there is considerable doubt as to whether the proposed language in § 192.610 is consistent with the original intent of the Part 192 regulations. Industry has long understood that the valve installation requirements do not apply retroactively to existing pipeline facilities if an operator replaces a pipeline segment in response to a class location change, particularly if the length of the segment is minimal. PHMSA's position, as reflected in the proposal to adopt § 192.610, creates significant barriers to pipeline replacements that may actually reduce public safety by imposing unjustifiable costs on the industry.

Rather than continuing to pursue an unreasonable position, PHMSA should establish valve installation requirements for class-location-related pipeline replacements that are less burdensome than those that apply to newly constructed pipeline systems. Most class-location-related pipeline replacements involve very short lengths of pipe, which makes compliance with the valve spacing

⁴¹ NPRM at 7,175. See also *In the Matter of Viking Gas Transmission*, CPF No. 32102 (May 1, 1998).

provisions in the design regulations unnecessary and impractical. Adopting longer spacing intervals avoids discouraging pipeline replacements and addresses potential concerns with retroactive application of the design requirements under the Pipeline Safety Act.⁴²

Rupture mitigation valves should be installed for class-location-related pipeline replacements at the alternative spacing intervals if the risk-based criteria in § 192.179(e) are satisfied.⁴³ Specifically, rupture mitigation valves should be required if the replaced segment is constructed with pipe 6 inches or greater in diameter, has an MAOP that produces a hoop stress greater than 30 percent of SMYS, and is in a Class 3 or Class 4 location or an HCA.⁴⁴ The installation of manual valves or use of equivalent technologies should also be permitted if the operator receives authorization under § 192.179(g).⁴⁵

Finally, PHMSA should consolidate all of the valve installation requirements for class-location-related pipeline replacements into § 192.611, the regulation that currently prescribes the requirements for confirming or revising MAOP in response to class location changes. To accomplish that objective, PHMSA should add an exception from the valve spacing intervals in § 192.179(a), withdraw § 192.610, rename § 192.611 to address MAOP confirmations or revisions and pipeline replacements, and add a new scope provision in § 192.611(a) that ties the general applicability of the requirements to the class location study required under § 192.609. The existing provisions for confirmation or revision of MAOP in response to class location changes can be renumbered as § 192.611(b)-(d) with minor clarifications. The new requirements for addressing pipeline replacements can be added in § 192.611(e) with a provision that addresses the general compliance obligations and subsequent provisions for valve spacing and rupture mitigation valve installation. The 24-month deadline can be renumbered as § 192.611(f) with minor clarifications.

B. Proposed Regulatory Language

§192.179 Transmission line valves.

(a) Each transmission line, other than offshore segments **and pipeline replacements made in accordance with the requirements of § 192.611(e)**, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

§192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure or replacement of pipeline segments.

(a) **The requirements in this section apply if the results of the study required under § 192.609 indicate that the hoop stress corresponding to the established maximum allowable operating pressure of a pipeline segment is not commensurate with the present class location.**

⁴² 49 U.S.C. § 60104(b).

⁴³ See *supra* Section VII.B.

⁴⁴ *Id.*

⁴⁵ *Id.*

(b) If the segment is in satisfactory physical condition, the operator may confirm or revise the maximum allowable operating pressure in accordance with one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(iii) For pipeline operating at an alternative maximum allowable operating pressure per §192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(c) The maximum allowable operating pressure of a segment confirmed or revised in accordance with paragraph (b) may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(d) Confirmation or revision of the maximum allowable operating pressure of a segment in accordance with paragraph (b) does not preclude the application of §§192.553 and 192.555.

(e) If the segment is replaced without confirmation or revision of the maximum allowable operating pressure, the operator must:

(1) Provide for the installation of valves to protect the replaced segment at intervals not to exceed

(i) 8 miles in total length if the replaced segment is in a Class 4 location;

(ii) 15 miles in total length if the replaced segment is in a Class 3 location; and

(iii) 20 miles in total length if the replaced segment is in a Class 2 location or Class 1 location.

(2) If the replaced segment meets the criteria in § 192.179(e), install rupture mitigation valves at the intervals prescribed in paragraph (e)(1) of this section, unless the installation of manual valves or use of an equivalent technology is authorized under § 192.179(f)-(g).

(f) Confirmation or revision of the maximum allowable operating pressure or replacement of a pipeline segment under this section must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a)(1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

IX. PHMSA Should Modify the Valve Location Requirements in § 195.260 by Consolidating Certain Provisions and Eliminating Others.

A. Comments

In the NPRM, PHMSA proposed several changes to the valve location requirements for hazardous liquid and carbon dioxide pipelines in § 195.260.⁴⁶ Specifically, PHMSA proposed new maximum spacing intervals for pipelines transporting HVLs (7.5 miles), pipelines that could affect HCAs (15 miles), and all other pipelines (20 miles). PHMSA also proposed to reference the provision in the integrity management regulations that requires consideration of emergency flow restricting devices (EFRDs) and to impose a new 7.5-mile-maximum-valve-spacing interval from the endpoint of any HCA pipeline segments. PHMSA proposed changes to the requirements for valves at water crossings that are more than 100-feet wide in § 195.260(e) as well. PHMSA proposed to make these changes by amending the provisions in two existing paragraphs in § 195.260 (paragraph (c) for mainline valves and paragraph (e) for water crossings) and creating a new paragraph (g) for HVL pipelines.

While used in the Part 192 regulations for many years, GPA Midstream does not support applying numeric thresholds for maximum valve spacing to hazardous liquid or carbon dioxide pipelines. The feasibility, practicability, and public safety benefits associated with installing a valve at a particular location vary depending on the unique circumstances of each pipeline system. Operating characteristics, topography, and other factors may make the installation of a valve

⁴⁶ NPRM at 7,186.

unnecessary or impracticable. The current language in § 195.260 recognizes that fact by using performance-based standards for determining where valves need to be installed and omitting arbitrary spacing intervals.⁴⁷

To the extent that PHMSA decides to adopt numeric thresholds, the proposed addition of a 7.5-mile-maximum valve spacing interval from the endpoint of any HCA pipeline segments should be eliminated. PHMSA does not provide any technical justification for that proposal in the NPRM, and the maximum valve spacing intervals proposed for HCA pipelines are more than adequate to protect these segments. The maximum valve spacing intervals for HVL, HCA, and non-HCA pipelines should also be consolidated in a new paragraph (g) at the end of § 195.260. Placing the requirements in a single paragraph avoids unnecessary duplication of regulatory language, provides greater clarity, and facilitates operator compliance. The proposed 7.5-mile maximum valve spacing interval for HVL pipelines should be increased to align with the comparable Canadian standards (15 km or approximately 9.3 miles).⁴⁸ PHMSA did not provide an adequate technical justification for a shorter distance in the NPRM, and a 10-mile limitation is more than adequate to protect HVL pipelines. As in the comparable Canadian pipeline safety standards, operators should be allowed to increase a maximum spacing interval by up to 25 percent in appropriate cases.

The proposed changes to the valve installation requirements for water crossings in § 195.260(e) should be simplified and consolidated into a single provision. Rather than establishing a 1-mile limitation for multiple crossings, the regulation should direct operators to install valves at locations that protect one or more water crossings meeting the 100-foot threshold outside of the 100-year flood plain or with actuators or other equipment not impacted by flood conditions. A new paragraph should also be added at the end of § 195.260 that allows operators to obtain a determination from the Associate Administrator for Pipeline Safety that the installation of a valve is not necessary in a particular case. Allowing the Associate Administrator for Pipeline Safety to make these determinations is preferable to requiring an operator to submit a petition for finding or approval to the PHMSA Administrator under 49 C.F.R. § 190.9 or obtain a special permit under § 190.341. Note that the applicability of the valve location requirements in § 195.260 would be subject to the 2,000-foot and 2-mile limitations proposed in § 195.200 for purposes of the language provided below.

B. Proposed Regulatory Language

§ 195.260 Valves: Location.

* * * * *

(c) On each mainline at locations:

(1) along the pipeline system that will minimize or prevent safety risks, property damage, or environmental harm from accidental hazardous liquid or carbon dioxide discharges, as appropriate for onshore areas, offshore areas, and high consequence areas.

⁴⁷ 49 C.F.R. § 195.260.

⁴⁸ CAN/CSA Z662-99, § 4.4.

(2) as determined using the process for identifying preventive and mitigative measures in § 195.452(i) for pipeline segments that could affect a high consequence area.

* * * * *

(e) Unless the Associate Administrator for Pipeline Safety determines under paragraph (h) of this section that the installation of a valve is not necessary in a particular case, at locations outside of the 100-year flood plain or with actuators or other equipment not impacted by flood conditions that provide adequate protection for water crossings that are more than 100 feet (30 meters) wide from high-water mark to high-water mark.

* * * * *

(g) Unless the Associate Administrator for Pipeline Safety determines under paragraph (h) of this section that the installation of a valve is not necessary in a particular case, on each mainline at a maximum spacing interval that does not exceed:

(1) 10 miles for pipeline segments transporting a highly volatile liquid (HVL) in a high population area or other populated area (as defined in § 195.450);

(2) 15 miles for pipeline segments that could affect a high consequence area (as defined in § 195.450); and

(3) 20 miles for pipeline segments that could not affect a high consequence area.

(4) The maximum valve spacing intervals in this paragraph may be increased to no more than 1.25 times the distance provided if an operator:

(i) Determines that the installation of a valve at a particular location is impracticable; and

(ii) Keeps the records necessary to support that determination for the useful life of the pipeline.

(h) To obtain a determination from the Associate Administrator for Pipeline Safety under paragraphs (e) or (g) of this section, an operator must send a notification to PHMSA by:

(1) electronic mail to InformationResourcesManager@dot.gov; or

(2) mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE, Washington, DC 20590; and

(3) Include the information required to demonstrate that the installation of a valve is not necessary in a particular case.

(4) The Associate Administrator shall decide whether the installation of a valve is necessary within 90 days of receiving the notification required under this section, unless the operator is

notified in writing that additional time is needed to complete the review. In cases where additional time is required, the Associate Administrator shall provide the operator with an expected deadline for making a final decision.

X. The Changes to the Requirements for Procedural Manuals for Operations, Maintenance, and Emergencies Should be Modified.

A. Comments

In the NPRM, PHMSA proposed to add a series of new requirements in § 195.402, the regulation that requires operators to develop and implement a manual of written procedures for performing operations and maintenance activities and handling abnormal operations and emergencies.⁴⁹ PHMSA proposed to add new provisions for investigating failures and accidents and analyzing failures and accidents that involve ruptures or the closure of a rupture mitigation valve. Other new provisions would be added as well, including a requirement that pipeline operators must determine if a rupture occurs as soon as practicable, but no later than 10 minutes after initial notification.

The proposed 10-minute rupture identification deadline lacks any technical justification and will force operators to treat many events that do not meet the applicable criteria as ruptures. Over classification of ruptures will create unnecessary disruptions in pipeline operations that may actually reduce public safety as acknowledged in the GAO report.⁵⁰ Rather than the proposed 10-minute deadline for rupture identification, PHMSA should provide operators with a 40-minute total response time for closing rupture mitigation valves, manual valves, or equivalent technology following a rupture. Ensuring that rupture mitigation valves are promptly closed in appropriate cases, not establishing arbitrary deadlines for identifying these events, creates the greatest benefit to public safety.

The requirements for investigating failures and accidents and incorporating lessons learned can be consolidated into a single provision, and much of the additional language proposed in the NPRM (sending the failed pipe, component, or equipment to a laboratory for testing, an exhaustive list of the procedures that may require revision to incorporate lessons learned, etc.) can be eliminated. The obligation to conduct the investigation and incorporate any lessons learned can be clearly and succinctly stated in the regulation. The same changes can be made to the provisions for analyzing failures and accidents that involve ruptures or rupture mitigation valves. Note that PHMSA proposed a senior executive officer review-and-signature and lifetime recordkeeping requirement for all analyses performed under the provision. To avoid creating unnecessary review and recordkeeping burdens, these provisions should only apply to the final analysis.

B. Proposed Regulatory Language

§ 195.402 Procedural manual for operations, maintenance, and emergencies.

⁴⁹ NPRM at 7,187.

⁵⁰ GAO Report at 24 (“For hazardous liquid pipelines, accidental closures can cause an incident, when a valve closes and the subsequent pressure buildup causes the pipeline to rupture”).

* * * * *

(c) * * *

(4) Determining which pipeline facilities are in areas that would require an immediate response by the operator to prevent hazards to the public, property, or the environment **in the event of a failure or malfunction.**

(5) Investigating failures and accidents that are reportable under §195.54 to determine the causes and contributing factors and minimize the possibility of a recurrence and incorporating the lessons learned that, if implemented, would otherwise have materially affected the occurrence or degree of mitigation of a rupture, into the procedures required under this part.

(6) If a failure or accident involves a rupture or the closure of a rupture mitigation valve:

(i) analyzing the factors impacting the volume and consequences of the release and identifying the preventive and mitigative measures necessary to minimize the volume and consequences of a future failure or incident. All relevant factors must be considered in the analysis, including, but not limited to, the following:

(A) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the release or failure event;

(B) Appropriateness and effectiveness of procedures and pipeline systems, including SCADA, communications, valve shut-off, and operator personnel;

(C) Actual response time from rupture detection to initiation of mitigative actions, and the appropriateness and effectiveness of the mitigative actions taken;

(D) Location and the timeliness of actuation of rupture-mitigation valves; and

(E) Any other factor the operator deems appropriate.

(ii) The scope of an analysis performed under paragraph (c)(6)(i) of this section may be limited based upon the magnitude and severity of the failure or accident.

(iii) Preparing a preliminary version of the analysis required under paragraph (c)(6)(i) of this section within 90 days of the failure or incident and conducting quarterly status reviews until the investigation is complete.

(iii) Preparing a final version of the analysis required under paragraph (c)(6)(i) of this section after completing the investigation that is:

(A) Reviewed, dated, and signed by the appropriate senior executive officer; and

(B) Kept for the useful life of the pipeline.

* * * * *

(13) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (9-1-1 emergency call center), as well as fire, police, and other public officials, to learn the responsibility, resources, jurisdictional area, and emergency contact telephone numbers for both local and out-of-area calls of each government organization that may respond to a pipeline emergency, and to inform the officials about the operator's ability to respond to the pipeline emergency and means of communication.

* * * * *

(e) * * *

(1) Receiving, identifying, and classifying notices of events that need immediate response by the operator or notice to the appropriate public safety answering point (9-1-1 emergency call center), as well as fire, police, and other appropriate public officials, and communicating this information to appropriate operator personnel for corrective action.

* * * * *

(4) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, and pressure reduction, in any section of the operator's pipeline system to minimize hazards of released hazardous liquid or carbon dioxide to life, property, or the environment. Each operator installing valves in accordance with § 195.258(c) or subject to the requirements in § 195.418 must also evaluate and identify a rupture as defined in § 195.2 as being an actual rupture event or non-rupture event in accordance with operating procedures as soon as practicable but within 10 minutes of the initial notification to or by the operator, regardless of how the rupture is initially detected or observed.

* * * * *

(7) Notifying the appropriate public safety answering point (9-1-1 emergency call center), as well as fire, police, and other public officials, of hazardous liquid or carbon dioxide pipeline emergencies to coordinate and share information to determine the location of the release, including both planned responses and actual responses during an emergency, and any additional precautions necessary for an emergency involving a pipeline transporting a highly volatile liquid. The operator (pipeline controller or the appropriate operator emergency response coordinator) must immediately and directly notify the appropriate public safety answering point (9-1-1 emergency call center) or other coordinating agency for the communities and jurisdictions in which the pipeline is located after the operator determines a rupture has occurred when a release is indicated and valve closure is implemented.

* * * * *

(10) Actions required to be taken by a controller during an emergency, in accordance with the operator's emergency plans and §§ 195.418 and 195.446.

XI. PHMSA Should Streamline the Provisions for Failure and Incident Investigations and Provide Additional Clarifications in § 192.617.

A. Comments

In the NPRM, PHMSA proposed changes to § 192.617 that would add new provisions for investigating failures and accidents and analyzing failures and accidents that involve ruptures or the closure of a rupture mitigation valve.⁵¹ Other new provisions would be added as well. As with many of the other proposals in the NPRM, the proposed changes to § 192.617 can be consolidated and revised to provide greater clarity. Certain unnecessary or repetitive language can also be omitted.

The obligation to prepare and follow procedures for conducting failure and incident investigations should be stated in a new paragraph (a), and the requirement to incorporate any lessons learned into appropriate Part 192 procedures can be consolidated into a single provision in a new paragraph (b). The other additional language proposed in the NPRM (sending the failed pipe, component, or equipment to a laboratory for testing, an exhaustive list of the procedures that may require revision to incorporate lessons learned, etc.) is unnecessary and can be eliminated. The obligation to conduct the investigation and incorporate any lessons learned can be effectively stated in a clear and concise fashion.

The same changes can be made to the provisions for analyzing failures and incidents that involve ruptures or rupture mitigation valves in a new paragraph (c). The proposals to require senior executive review and establish a lifetime recordkeeping requirement for all analyses performed under § 192.617 are unnecessary. To avoid imposing undue burdens on pipeline operators, the senior executive review and lifetime recordkeeping requirements should only apply to the final analysis prepared at the conclusion of the investigation as provided in the new paragraph (d).

B. Proposed Regulatory Language

§ 192.617 Investigation of failures **and incidents.**

(a) *Procedures*. Each operator must establish and follow procedures for investigating failures and incidents to determine the causes and contributing factors and minimize the possibility of a recurrence.

(b) *Lessons learned*. Each operator must incorporate the lessons learned from a failure or incident investigation into the procedures required under this part.

⁵¹ NPRM at 7,183.

(c) *Analysis of rupture and valve shut-offs; preventive and mitigative measures.* If a failure or incident involves a rupture or the closure of a rupture mitigation valve, the operator must analyze the factors impacting the volume and consequences of the release and identify the preventive and mitigative measures necessary to minimize the volume and consequences of a future failure or incident. All relevant factors must be considered in the analysis, including, but not limited to, the following:

(1) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the release or failure event;

(2) Appropriateness and effectiveness of procedures and pipeline systems, including SCADA, communications, valve shut-off, and operator personnel;

(3) Actual response time from rupture detection to initiation of mitigative actions, and the appropriateness and effectiveness of the mitigative actions taken;

(4) Location and the timeliness of actuation of rupture-mitigation valves; and

(5) Any other factor the operator deems appropriate.

(d) *Preliminary and final analysis.* The operator must prepare a preliminary version of the analysis required under paragraph (c) of this section within 90 days of the failure or incident and conduct quarterly status reviews until the investigation is complete. The operator must also prepare a final version of the analysis after completing the investigation that is:

(1) Reviewed, dated, and signed by the appropriate senior executive officer; and

(2) Kept for the useful life of the pipeline.

* * * * *

XII. The Operations Requirements for Rupture Mitigation Valves in § 192.634 and § 195.418 Should Modified and Any Provisions that Belong in the Design or Construction Requirements Should be Eliminated.

A. Comments

In the NPRM, PHMSA proposed to add new operations requirements for rupture mitigation valves in § 192.634 and § 195.418.⁵² Both proposals restated the criteria for installing rupture mitigation valves, as well as requirements for maximum valve spacing intervals, valve shut-off time, valve capabilities and methods, and valve monitoring and response status. As with many of the other proposals in the NPRM, the proposed language is confusing and repetitive. The provisions also incorporate spacing requirements for rupture mitigation valves, which are unnecessary given the language in §§ 192.179, 192.611, 195.258, and 195.260. Operators make decisions about valve spacing before a pipeline goes into service, not during operations. To

⁵² NPRM at 7,183–84, 7,187–88.

provide greater clarity and avoid potential retroactivity concerns, the proposed valve spacing requirements should be eliminated from § 192.634 and § 195.418.

Rather than restating all of the criteria used to determine if a rupture mitigation valve needs to be installed, a scope provision can be added at the outset of § 192.634 and § 195.418 that limits the requirements to rupture mitigation valves installed under § 192.179(e) or § 195.258(c) and manual valves or equivalent technologies authorized under § 192.179(f)-(g) or § 195.258(d)-(e). A clearly articulated scope provision will eliminate uncertainty and facilitate operator compliance. The references to valves spacing intervals, which are installation requirements that should be addressed in the non-retroactive subparts of Part 192 and Part 195, should be eliminated for the reasons previously discussed. Nor is there any apparent need to include the requirements proposed in both sections for laterals.

The valve shut-off time requirements can be stated more clearly in both regulations in a new paragraph (b). The 40-minute deadline from rupture identification included within that new paragraph need only reference valves necessary to minimize the volume of gas or hazardous liquid or carbon dioxide released from a pipeline and mitigate the safety and environmental consequences of a rupture. Operators should also be allowed to seek authorization from the Associate Administrator for Pipeline Safety to use an alternative shut-off time in appropriate cases. As with any bright-line requirement, there may be circumstances where an operator cannot meet the 40-minute shut-off time, and the regulation should provide a mechanism for allowing a longer time interval, subject to appropriate review and authorization from the Associate Administrator.

With regard to the remaining requirements, the addition of the scope provisions renders the additional language proposed in the NPRM unnecessary. The provisions for valve shut-off capability and methods can be consolidated to further improve clarity given the limitations included in the scope provision for the new sections. The requirements for manually-operated valves, valve monitoring and operations capabilities, and monitoring of valve shutoff response status can also be consolidated and restated more clearly to facilitate operator compliance.

B. Proposed Regulatory Language

§ 192.634 Transmission lines: Rupture mitigation valves.

(a) *Scope.* The requirements in this section apply to:

(1) Rupture mitigation valves installed under § 192.179(e); and

(2) Manual valves or equivalent technologies authorized under § 192.179(f)-(g).

(b) *Shut-off time.* As soon as practicable, but no later than 40 minutes after rupture identification, an operator must fully close any valve necessary to minimize the volume of gas released from a pipeline and mitigate the safety and environmental consequences of a rupture, unless the Associate Administrator for Pipeline Safety authorizes an alternative shut-off time under paragraph (h) of this section.

(c) *Valve shut-off capability.* A valve must have the actuation capability necessary to mitigate the consequences of a rupture in accordance with the requirements of this section.

(d) *Valve shut-off methods.* A rupture mitigation valve must be actuated by one of the following methods:

(1) Remote control from a location that is continuously staffed with personnel trained in rupture response to provide immediate shut-off;

(2) Automatic shut-off; or

(3) Equivalent technology that is capable of mitigating a rupture in accordance with the requirements of this section.

(e) *Manual operation.* An operator that installs a manual valve or uses an equivalent technology under § 192.179(f)-(g) must appropriately station personnel to meet the shut-off requirements in paragraph (a) of this section. In determining where to station personnel, an operator must consider:

(1) the time for assembly of necessary operating personnel;

(2) the time for acquisition of necessary tools and equipment;

(3) driving time under heavy traffic conditions and at the posted speed limit;

(4) walking time to access the valve; and

(5) and the time to manually shut off all valves.

(f) *Valve monitoring and operation capabilities.* A rupture mitigation valve must be capable of being:

(1) Monitored or controlled by either remote or onsite personnel;

(2) Operated during normal, abnormal, and emergency operating conditions;

(3) Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. Pipeline segments that use a manual valve or equivalent technology must have the capability to monitor pressures and gas flow rates on the pipeline to be able to identify and locate a rupture; and

(4) Monitored and controlled by remote personnel or must have a back-up power source to maintain SCADA or other remote communications for remote control shut-off valve or automatic shut-off valve operational status.

(g) *Monitoring of valve shut-off response status.* The position and operational status of a rupture mitigation valve must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means.

(h) *Notification.* To obtain authorization for alternative shut-off time from the Associate Administrator for Pipeline Safety under paragraph (b) of this section, an operator must send a notification to PHMSA 90 days in advance by:

(1) electronic mail to InformationResourcesManager@dot.gov; or

(2) mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE, Washington, DC 20590; and

(3) Including the information required to demonstrate that compliance with the 40-minute shut-off time in paragraph (b) of this section is economically, technically, or operationally infeasible in a particular case and providing an alternative shut-off time for approval.

(4) The Associate Administrator shall decide whether to authorize an alternative shut-off within 90 days of receiving the notification required under this paragraph, unless the Associate Administrator notifies the operator in writing that additional time is needed to complete the review. In cases where additional time is required, the Associate Administrator shall provide the operator with an expected deadline for making a final decision.

§ 195.418 Rupture mitigation valves.

(a) *Scope.* The requirements in this section apply to:

(1) Rupture mitigation valves installed under § 195.258(c); and

(2) Manual valves or equivalent technologies authorized under § 195.258(d)-(e).

(b) *Shut-off time.* As soon as practicable, but no later than 40 minutes after rupture identification, an operator must fully close any valve necessary to minimize the volume of hazardous liquid or carbon dioxide released from a pipeline and mitigate the safety and environmental consequences of a rupture, unless the Associate Administrator for Pipeline Safety authorizes an alternative shut-off time under paragraph (h) of this section.

(c) *Valve shut-off capability.* A valve must have the actuation capability necessary to mitigate the consequences of a rupture in accordance with the requirements of this section.

(d) *Valve shut-off methods.* A rupture mitigation valve must be actuated by one of the following methods:

(1) Remote control from a location that is continuously staffed with personnel trained in rupture response to provide immediate shut-off;

(2) Automatic shut-off; or

(3) Equivalent technology that is capable of mitigating a rupture in accordance with the requirements of this section.

(e) *Manual operation.* An operator that installs a manual valve or uses an equivalent technology under § 195.258(d)-(e) must appropriately station personnel to meet the shut-off requirements in paragraph (a) of this section. In determining where to station personnel, an operator must consider:

(1) the time for assembly of necessary operating personnel;

(2) the time for acquisition of necessary tools and equipment;

(3) driving time under heavy traffic conditions and at the posted speed limit;

(4) walking time to access the valve; and

(5) and the time to manually shut off all valves.

(f) *Valve monitoring and operation capabilities.* A rupture mitigation valve must be capable of being:

(1) Monitored or controlled by either remote or onsite personnel;

(2) Operated during normal, abnormal, and emergency operating conditions;

(3) Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. Pipeline segments that use a manual valve or equivalent technology must have the capability to monitor pressures and hazardous liquid or carbon dioxide flow rates on the pipeline to be able to identify and locate a rupture; and

(4) Monitored and controlled by remote personnel or must have a back-up power source to maintain SCADA or other remote communications for remote control shut-off valve or automatic shut-off valve operational status.

(g) *Monitoring of valve shut-off response status.* The position and operational status of a rupture mitigation valve must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means.

(h) *Notification.* To obtain authorization for alternative shut-off time from the Associate Administrator for Pipeline Safety under paragraph (b) of this section, an operator must send a notification to PHMSA 90 days in advance by:

(1) electronic mail to InformationResourcesManager@dot.gov; or

(2) mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE, Washington, DC 20590; and

(3) Including the information required to demonstrate that compliance with the 40-minute shut-off time in paragraph (b) of this section is economically, technically, or operationally infeasible in a particular case and providing an alternative shut-off time for approval.

(4) The Associate Administrator shall decide whether to authorize an alternative shut-off within 90 days of receiving the notification required under this paragraph, unless the Associate Administrator notifies the operator in writing that additional time is needed to complete the review. In cases where additional time is required, the Associate Administrator shall provide the operator with an expected deadline for making a final decision.

XIII. To Improve the Clarity of the Proposed Regulations, PHMSA Should Modify the Valve Maintenance Requirements in § 195.420.

A. Comments

In the NPRM, PHMSA proposed changes to the valve maintenance requirements in § 195.420.⁵³ Specifically, PHMSA proposed to require that rupture mitigation valves be partially operated as part of the inspections that need to occur twice each calendar year. PHMSA also proposed to require operators to perform certain control-room-management-related activities as part of valve maintenance. These provisions can be revised for clarity.

Requiring a 40-minute shutoff timeframe from the point of rupture identification may not be practicable in all cases. For example, in a case study cited in the GAO report to demonstrate improved response time, an operator with automated valves was only able to limit response time to within an hour.⁵⁴ Response time standards established by the New Hampshire Public Utilities Commission, which are also cited in the GAO report, do not require 100% compliance with established response time targets of up to one hour.⁵⁵ The maintenance procedures should be revised to incorporate a mechanism for obtaining an authorized alternative response time as proposed in Section XII.

In addition, the proposed 6-month timeframe for repairing or replacing a rupture mitigation valve may not be practical in certain cases, including where parts are unavailable or where access to the location of repair or replacement is difficult or restricted. The applicable repair and replacement timeframe should be driven by operator-specific procedures that are already subject to PHMSA inspection. Finally, clarification should be made to the provision requiring designation

⁵³ NPRM at 7,188–89.

⁵⁴ GAO Report at 26.

⁵⁵ *Id.* at p. 16.

of an alternative valve within 14 calendar days after a finding of a need to repair or replace a rupture mitigation valve, such that this requirement applies only if an alternative valve already is installed.

B. Proposed Regulatory Language

§ 195.420 Valve maintenance.

* * * * *

(b) Each operator must:

(1) At intervals not exceeding 7 1/2 months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly; and

(2) Partially operate each rupture mitigation valve installed under § 195.258(c), or manual valve or equivalent technology authorized under § 195.258(d)-(e), as part of that inspection.

* * * * *

(d) For each rupture mitigation valve installed under § 195.258(c) or, if appropriate, equivalent technology authorized under § 195.258(d)-(e), the operator must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with § 195.446(c) and (e) or perform an equivalent verification.

(e) For each rupture mitigation valve installed under § 195.258(c) or manual valve or equivalent technology authorized under § 195.258(d)-(e) that is manually or locally operated:

(1) Operators must establish the 40-minute total response time as required by § 195.418(b), or alternate response time as authorized under § 195.418(h), through an initial drill and through periodic validation as required in paragraph (e)(2) of this section. Each phase of the drill response must be reviewed and the results documented to validate the total response time, including valve shut-off, as being less than or equal to 40 minutes (or the authorized alternative response time) following rupture identification.

(2) A mainline valve within each pipeline system must be randomly selected for an annual 40-minute or authorized alternative total response time validation drill that simulates worst-case conditions for that location to ensure compliance. The response drill must occur at least once each calendar year, with intervals not to exceed 15 months.

(3) If the 40-minute or authorized alternative maximum response time cannot be validated or achieved in the drill, the operator must revise response efforts to achieve compliance with § 195.418, and implement alternative valve shut-off measures in accordance with paragraph (f) of this section not later than 6 months after the drill.

(4) Based on the results of response-time drills, the operator must include lessons learned in:

(i) Training and qualifications programs; and

(ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and

(iii) Any other areas identified by the operator as needing improvement.

(f) Each operator must take remedial measures to correct any rupture mitigation valve, manual valve, or equivalent technology installed or authorized under § 195.258(c)-(e) that is found to be inoperable or unable to maintain shut-off, as follows:

(1) Repair or replace the valve as soon as practicable but no later than the timeframe for repair or replacement specified in the operator's procedural manual for operations and maintenance under § 195.402; and

(2) If an alternative valve is already installed at the pipeline segment, designate an alternative valve within 14 calendar days of the finding while repairs are being made.

XIV. PHMSA Should Clarify the Valve Maintenance Requirements in § 192.745 and Move Drill Provisions to § 192.615.

A. Comments

In the NPRM, PHMSA proposed changes to § 192.745 to reference the maintenance requirements for valves installed under both § 192.179 and § 192.634.⁵⁶ For purposes of clarity, the regulation should only reference § 192.179, which is the regulation that requires the installation of rupture mitigation valves or authorizes the use of manual valves or equivalent technology.

As previously discussed, repair or replacement of a rupture mitigation valve may not be practicable within the proposed 6-month timeframe. Operators should be required to make repairs or replacements as soon as practicable but no later than the time provided in their procedures for conducting operations, maintenance, and emergency activities. Finally, an alternative may not always be available in cases where a rupture mitigation valve is being repaired, and a 7-day timeframe may not be sufficient to locate and designate an alternative valve to serve as a substitute. The provision should be revised to allow 14 days for designating an alternative valve, if available.

B. Proposed Regulatory Language

§ 192.745 Valve maintenance: Transmission lines.

* * * * *

⁵⁶ NPRM at 7,185.

(c) For each rupture mitigation valve installed under § 192.179(e) or, if appropriate, equivalent technology used under § 192.179(f), the operator must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with § 192.631(c) and (e), if applicable.

* * * * *

(e) Each operator must take remedial measures to correct any rupture mitigation valve, manual valve, or equivalent technology installed or used under § 192.179(e)-(f) that is found to be inoperable or unable to maintain shut-off, as follows:

(1) Repair or replace the valve as soon as practicable but no later than the timeframe provided in the operator's procedural manual for operations, maintenance, and emergencies in § 192.605; and

(2) If available, designate an alternative valve within 14 calendar days of the finding while repairs are being made, unless there are no other alternative valves available on the segment.

* * * * *

XV. The Preventative and Mitigative Measures Provision for Rupture Mitigation Valves Should Be Consolidated in the Hazardous Liquid Integrity Management Regulations.

A. Comments

In the NPRM, PHMSA proposed to add language to the preventative and mitigative measures provision in the IM regulations for EFRDs.⁵⁷ The proposed language appears to require that EFRDs comply with the provisions for rupture mitigation valves if installed on a pipeline that meets the criteria in § 195.258(c). Such a provision does not appear to be necessary because an EFRD is a type of rupture mitigation valve that would already be subject to § 195.258(c) at the time of installation. PHMSA also proposed additional language directing operators to complete an EFRD analysis under the IM regulations before placing a pipeline that meets the rupture mitigation valve installation requirements in § 195.258(c) into service. As with the language discussed above, such a provision does not appear to be necessary because compliance with § 195.258(c) is required before a pipeline is placed into service. To the extent that further clarification is needed, PHMSA should simply reiterate that EFRDs installed under the IM regulations must meet the applicable requirements in Part 192 for rupture mitigation valves.

B. Proposed Regulatory Language

§ 195.452 Pipeline integrity management in high consequence areas.

* * * * *

⁵⁷ NPRM at 7,189.

(i) * * *

(4) Emergency Flow Restricting Devices (EFRD). If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors—the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size. **An EFRD installed under this paragraph must meet all of the applicable requirements in this part for rupture mitigation valves.**

* * * * *

XVI. PHMSA Should Clarify the Preventative and Mitigative Measures Provision for Rupture Mitigation Valves in the Gas Transmission Integrity Management Regulations.

A. Comments

In the NPRM, PHMSA proposes to include additional criteria for conducting a risk analysis to determine whether ASVs or RCVs would be an efficient means of protecting a HCA in the event of a release that would apply to new pipeline systems that are 6 inches or greater in diameter or where 2 or more miles of pipe has been replaced.⁵⁸ The criteria focus on whether the ASVs or RCVs are capable of satisfying the proposed operations and maintenance requirements for rupture mitigation valves. PHMSA also proposes periodic evaluations of the risk analysis required under § 192.933. As with many of the other proposals in the NPRM, the suggested changes to the IM regulations can be consolidated to provide further clarity and eliminate unnecessary provisions.

Rather than referencing ASVs or RCVs, the proposed modification to the risk analysis requirement in the preventative and mitigative measures provision can simply use the defined term rupture mitigation valve.⁵⁹ The other proposed changes, including the requirement to consider other regulations that apply to the operation and maintenance of rupture mitigation valves in conducting the risk analysis, are not necessary. The provision can simply reiterate that rupture mitigation valves installed as a result of the risk analysis required under the IM regulations must comply with all other applicable provisions in Part 192.

The proposed requirement to conduct periodic evaluations of the risk analysis for rupture mitigation valve installation is not necessary. PHMSA is not proposing to add a comparable provision in the IM regulations for hazardous liquid or carbon dioxide pipelines that could affect an HCA. PHMSA has also explained in enforcement cases, operators have an obligation periodically evaluate whether additional preventative or mitigative measures are required on newly

⁵⁸ NPRM at 7,185.

⁵⁹ See *supra* Section IV.B.

identified covered segments, which includes updating risk analyses on RCVs and ASVs.⁶⁰ Accordingly, the periodic evaluation provision should be eliminated.

B. Proposed Regulatory Language

§ 192.935 What additional preventive and mitigative measures must an operator take?

* * * * *

(c) *Risk analysis for gas releases and protection against ruptures.* If an operator determines, based on a risk analysis, that a rupture mitigation valve would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the rupture mitigation valve. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel. A rupture mitigation valve installed under this paragraph must meet all of the other applicable requirements in this part.

XVII. Conclusion

GPA Midstream appreciates the opportunity to submit these comments. If you have questions, please contact Matt Hite at GPA Midstream at (202) 279-1664 or by email at mhite@GPAglobal.org.

Sincerely,



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⁶⁰ *In the matter of Tennessee Gas Pipeline Co.*, CPF No. 4-2016-1004, Final Order at 6 (May 3, 2018) (concluding that “a broader evaluation of the need for any preventative and mitigative measures, including but not limited to RCVs and/or ASVs, is an integral part of the periodic evaluation requirement of § 192.937(b).”).