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Docket # PHMSA-2013-0255

JOINT COMMENTS

submitted by the

AMERICAN PETROLEUM INSTITUTE

and

ASSOCIATION OF OIL PIPE LINES

and

GPA MIDSTREAM ASSOCIATION

on

LIQUID PIPELINE ADVISORY COMMITTEE MEETING

July 23, 2020

for

“Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards”

Notice of Proposed Rulemaking Published by the Pipeline and Hazardous Materials Safety Administration.

U.S. DEPARTMENT OF TRANSPORTATION

85 Fed. Reg. 7162 (February 6, 2020)

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

To Whom It May Concern:

On July 23, 2020, the Pipeline and Hazardous Materials Safety Administration (PHMSA or Agency) convened a meeting of the Liquid Pipeline Advisory Committee (LPAC or Committee) to review a notice of proposed rulemaking (NPRM) in the above-captioned proceeding.[1] In the NPRM, PHMSA proposed to establish new valve installation and minimum rupture detection standards for hazardous liquid and carbon dioxide pipelines in 49 C.F.R. Part 195. The American

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

Petroleum Institute (API),[2] Association of Oil Pipe Lines (AOPL),[3] and GPA Midstream Association (GPA Midstream)[4] (collectively, Liquid Pipeline Associations) attended the LPAC meeting and are submitting these supplemental comments for the Agency's consideration in developing the final rule.

I. Summary

The Liquid Pipeline Associations respectfully request that PHMSA:

- Adopt a practical definition of "rupture" and allow operators to establish rupture identification criteria in their written procedures.
- Limit the rupture mitigation valve installation requirements to replacements of 2 or more miles of contiguous pipe in existing pipeline systems.
- Provide an exception to the rupture mitigation valve installation requirements for gathering lines due to the lack of public notice and other fundamental flaws in the rulemaking process.
- Provide an exception to the rupture mitigation valve installation requirements for low-stress pipelines and clarify the process for using manual valves or equivalent technology.
- Consolidate any maximum valve spacing intervals into a single provision, provide a 25 percent tolerance for highly volatile liquid (HVL) pipelines, and allow operators to seek approval of alternative spacing intervals in appropriate cases.
- Eliminate the 10-minute rupture identification deadline and allow operators to obtain an extension of the 30-minute rupture mitigation valve shutoff deadline in appropriate situations.
- Clarify the operations and maintenance requirements for rupture mitigation valves.

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

[3] AOPL promotes responsible policies, safety excellence, and public support for liquids pipelines. AOPL represents pipelines transporting 97 percent of all hazardous liquids barrel miles reported to the Federal Energy Regulatory Commission. AOPL's diverse membership includes large and small pipelines carrying crude oil, refined petroleum products, NGLs, and other liquids.

[4] GPA Midstream has served the U.S. energy industry since 1921. GPA Midstream is composed of close to seventy member companies 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.

II. Definitions

This section includes supplemental comments and proposed final rule language for the definitions for rupture, rupture identification, and rupture mitigation valve. As previously noted, the Liquid Pipeline Associations respectfully request that PHMSA adopt a practical definition of rupture, allow operators to establish criteria for rupture identification in their written procedures, and add a definition for rupture mitigation valve to clarify the provisions in the final rule.

A. Comments

In the NPRM, PHMSA proposed to define the term "rupture" as any of three listed "events that involve an uncontrolled release of a large volume of hazardous liquid or carbon dioxide[.]"[5] The primary event would be "[a]n unanticipated or unplanned flow rate change of 10 percent or greater or a pressure loss of 10 percent or greater, occurring within a time interval of 15 minutes or less, unless the operator has documented in advance of the flow rate change or pressure loss the need for a higher flow rate change or higher pressure-change threshold due to pipeline flow dynamics and terrain elevation changes that cause fluctuations in hazardous liquid or carbon dioxide flow that are typically higher[.]"[6]

The two other events that the Agency included in the proposed rupture definition were "[a]n unexplained flow rate change, pressure change, instrumentation indication or equipment function" or "the observ[ation] and report[ing] to the operator" of a release "that may be representative" of a flow rate change or pressure loss meeting the numerical thresholds listed in the primary event.[7] In a note accompanying the proposed definition, PHMSA included language stating that "[r]upture identification occurs when a rupture . . . is first observed by or reported to pipeline operating personnel or a controller."[8]

In their written comments, the Liquid Pipeline Associations opposed PHMSA's proposed rupture definition, explaining that the numerical thresholds lacked a technical basis and would require operators to treat many routine events as ruptures, leading to numerous false alarms, unnecessary valve closures, and service disruptions.[9] The Liquid Pipeline Associations further explained that the provision authorizing operators to document alternative rupture thresholds was not clear, and that the definition included unnecessary provisions that simply referred back to the numerical thresholds established in the primary event. To address these concerns, the Liquid Pipeline Associations asked the Agency to adopt a practical definition of "rupture" based on the guidance provided in the instructions for the Part 195 accident reporting Form F7000-1.[10] The

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[5] NPRM at 7,186.
[6] *Id.*
[7] *Id.*
[8] *Id.*
[9] Matthew Hite Comments GPA Midstream at 5-7, PHMSA-2013-0255-0020 (Apr. 6, 2020) (GPA Comments); David Murk and Andrew Black Comments of the American Petroleum Institute and the Association of Oil Pipe Lines at 4-6 (Apr. 6, 2020) (API/AOPL Comments).
[10] GPA Comments at 6; API/AOPL Comments at 5. *See* Instructions (rev 12-2015) for Form PHMSA F7000-1 (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-

Liquid Pipeline Associations also urged PHMSA to adopt a separate definition for the term "rupture identification" using a reasonableness standard similar to the definition for confirmed discovery in the Part 195 reporting requirements.[11] The Liquid Pipeline Associations asked the Agency to define "rupture mitigation valve" to clarify the subsequent provisions of the rule as well.

PHMSA responded to some of these comments in its presentation to the LPAC. In particular, the Agency noted that operators could document a higher flow-rate or pressure-rate change in their written procedures under the proposed rupture definition. PHMSA also presented a slightly revised definition for the term "notification of potential rupture" for the LPAC's consideration.[12]

The Liquid Pipeline Associations offered additional public comments after the Agency's presentation to the LPAC.[13] GPA Midstream stated that the revised definition still contained unnecessary provisions and urged PHMSA to adopt the practical guidance provided in the instructions for the Part 195 accident reporting form.[14] GPA Midstream also emphasized that the definition needed to clearly distinguish between rupture notification, identification, and response, and that any timelines for closing rupture mitigation valves should run from the point of rupture identification. API expressed support for these comments and noted that the proposed numerical thresholds in the rupture definition were not operationally feasible.[15]

The industry LPAC members voiced the same concerns during the Committee's deliberations, explaining that PHMSA's proposed rupture definition contained prescriptive, one-size-fits-all, numeric thresholds that would not allow operators to make practical decisions.[16] The industry LPAC members also noted that the proposed definition did not appear to reflect recent industry technical initiatives or to account for the role that other regulations, particularly the control room management requirements, play in rupture identification and response; that the record did not contain a technical basis for the 10-percent and 15-minute numerical thresholds; and that rupture determinations should not be made solely on the basis of changes in pressure or flow rate in any event.[17] One industry LPAC member noted that applying the criteria in the proposed definition to a new pipeline system operated by his company generated *46 potential ruptures in a 12-hour period*.[18]

Rather than requiring operators to document a basis for deviating from the proposed numerical thresholds, the industry LPAC members urged PHMSA to allow operators to develop

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112-2015-and-beyond.pdf. That definition states that a rupture occurs when a pipeline has "burst, split, or broken and the operation of the pipeline facility is immediately impaired[,]" resulting in an uncontrolled, large volume release of hazardous liquid or carbon dioxide. *Id.* at 15.

[11] 49 C.F.R. § 195.2 ("*Confirmed discovery* means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.").

[12] LPAC Transcript at 47-48; PHMSA Presentation at 36 (July 22, 2020), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1118.

[13] *Id.* at 56-61.

[14] *Id.* at 57.

[15] *Id.* at 58.

[16] *Id.* at 66.

[17] *Id.* at 65-67.

[18] *Id.* at 67 (emphasis added).

rupture identification criteria in their written procedures.[19] The other Committee members responded favorably to these points, and the Agency presented a revised version of the rupture definition to the Committee that did not contain the numeric thresholds.[20] The LPAC ultimately approved a unanimous recommendation to PHMSA that the definition of rupture be changed to reflect the points raised during the Committee's deliberations.[21]

The Liquid Pipeline Associations support the LPAC's recommendation to change the rupture definition. The 10-percent and 15-minute numerical thresholds lack any technical basis in the record and should be eliminated in favor of a general definition of rupture that incorporates the concepts used in the Part 195 accident reporting forms. The Liquid Pipeline Associations do not support introducing the concept of "notification" into the rupture definition. Notification generally refers to the act of providing written notice of legally significant information, and that is the way that the term is used elsewhere in the NPRM and in PHMSA's regulations. A rupture is an event, not a legal document or regulatory filing, and operators do not receive notifications about potential ruptures, at least not within the ordinary understanding of that term. Moreover, the real point of significance from a regulatory perspective should be when the operator has sufficient information to identify a rupture, not when the operator receives any information that could be indicative of a potential rupture. To eliminate any doubt on these points, the Liquid Pipeline Associations urge the Agency to eliminate the "notification of potential rupture" concept from the final rule.

PHMSA should also develop a separate definition for rupture identification that incorporates a reasonableness standard and requires operators to specify the criteria used in making these determinations in their written procedures. To provide operators with additional guidance for developing those written procedures, the Liquid Pipeline Associations suggest that the Agency add appropriate language to 49 C.F.R. § 195.402(e)(4), the regulation that requires operators to develop and implement a procedural manual for conducting operations and maintenance activities and for responding to abnormal operations and emergencies.

Finally, the Liquid Pipeline Associations continue to support adding a definition for rupture mitigation valve to clarify the subsequent provisions in the rule. Adding a rupture mitigation valve definition allows the Agency to eliminate the repetitive references to "automatic shutoff valve" or "remote-control valve" that occur throughout the rule. The Liquid Pipeline Associations continue to support including check valves within the definition of rupture mitigation valve. Many operators use check valves as emergency flow restricting devices (EFRDs) under the integrity management regulations, and PHMSA has not presented any technical basis for excluding check valves from the rupture mitigation valve definition. The Agency should include language stating the purpose of rupture mitigation valves in the definition to distinguish other valves that may be installed or used for another reason.

B. Proposed Final Rule Language

§195.2 Definitions.

[19] *Id.* (proposing PHMSA use the language contained in the F 7000-1 report).
[20] *Id.* at 84-85.
[21] *Id.* at 117-119.

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Rupture means the unintentional bursting, breaking, or splitting of a pipeline that causes immediate operational impairment and results in an uncontrolled, large volume release of hazardous liquid or carbon dioxide.

Rupture identification means that a pipeline operator has sufficient information, based on the criteria established in the written procedures required under this part, to reasonably determine that a rupture occurred.

Rupture mitigation valve means an automatic shut-off valve (including a check valve) or 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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III. Rupture Mitigation Valve Installation

This section includes supplemental comments and proposed final rule language for the rupture mitigation valve installation requirements. As a result of the discussions at the LPAC meeting and the Committee's recommendations, the Liquid Pipeline Associations suggest that the rupture mitigation valve installation requirements be codified in a new section, § 195.259 Valves: Rupture Mitigation, rather than as an amendment to § 195.258 Valves: General. The Liquid Pipeline Associations believe that adding a new section for rupture mitigation valve installation will provide greater clarity and facilitate compliance.

A. Comments

i. Pipeline Replacements

In the NPRM, PHMSA proposed to amend 49 C.F.R. § 195.258 to require the installation of rupture mitigation valves on all new pipeline systems and replacements of 2 or more miles of contiguous pipe in existing pipeline systems with diameters of six inches or greater.[22] The Liquid Pipeline Associations generally supported these limitations in their written comments, but asked the Agency to add clarifying language in § 195.200, the regulation that establishes the scope of the construction requirements in Subpart D, rather than in § 195.258.[23]

To address concerns raised by other commenters, PHMSA presented the Committee with a modified version of the rupture mitigation valve installation requirement for pipeline replacements at the LPAC meeting. Specifically, the Agency proposed that rupture mitigation valves be required if 2 or more aggregate miles of pipe is replaced in any contiguous 5-mile segment during a 24-month period.[24] PHMSA did not explain how the modified provision satisfied the congressional mandate in in Section 4 of the Pipeline Safety, Regulatory Certainty, and Job

[22] NPRM at 7,186.
[23] GPA Comments at 10; API/AOPL Comments at 8.
[24] LPAC Transcript at 128-29.

Creation Act of 2011 (2011 Act),[25] which directed PHMSA to establish regulations, if appropriate, that require 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]."[26] The Committee nonetheless voted in favor of the Agency's modified proposal.[27]

The Liquid Pipeline Associations do not support the LPAC's recommendation to adopt PHMSA's modified limitation for pipeline replacements. While the Agency has some latitude in interpreting Section 4, the Liquid Pipeline Associations do not agree that a pipeline facility is "entirely replaced" if 2 or more miles of pipe in any contiguous 5-mile segment is replaced during a 24-month period.[28] In fact, the Liquid Pipeline Associations do not believe that replacing only 40 percent of the pipe in a 5-mile segment could ever make a pipeline facility "entirely replaced" for purposes of the statute.[29]

For these reasons, the Liquid Pipeline Associations urge PHMSA to retain the 2-or-more-miles of contiguous pipe limitation as proposed in the NPRM. That provision establishes an appropriate minimum mileage threshold and requires an operator to replace all of the pipe if that threshold is met. The Liquid Pipeline Associations do not object to a 24-month window for evaluating the 2-or-more-mile limitation in the event that the Agency is able to substantiate legitimate concerns about potential piecemeal replacements, although there is no indication in the record that operators would delay or defer any projects to avoid installing rupture mitigation valves.

ii. Gathering Lines

In the NPRM, PHMSA proposed to mandate the installation of rupture mitigation valves on new pipeline systems and certain replacements of existing pipeline systems with diameters of

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[25] Pub. L. 112-90 § 4 (Jan. 3, 2012), 125 Stat. 1904, 1907.
[26] 49 U.S.C. § 60102(n)(1) (2018) (emphasis added).
[27] LPAC Transcript at 178-81.
[28] The ordinary meaning of the term "entirely" is "to the full or entire extent" or "completely". https://www.merriam-webster.com/dictionary/entirely. An operator does not replace a transmission pipeline facility "to the full or entire extent" by replacing 2 miles of pipe in a 5-mile segment. Indeed, the operator does not even replace a majority of the pipe in the segment in that scenario.
[29] Although reviewing courts grant agencies some level of deference in construing ambiguous terms in the statutes they administer (*See Murray Energy Corp. v. EPA*, 936 F.3d 597, 608 (D.C. Cir. 2019)), agency interpretations must follow the traditional cannons of statutory interpretation, including the assumption that Congress' choice to modify "pipeline" with "entire" in Section 4 was not surplusage. (*See Murphy Exploration and Prod. Co. v. US Dep't. of Interior*, 252 F.3d 473, 481 (D.C. Cir. 2001) (*quoting Qi-Zhuo v. Meissner*, 70 F.3d 136, 139 (D.C. Cir. 1995)). *See also Rimini St., Inc. v. Oracle USA, Inc.*, -- U.S. --, 139 S.Ct. 881 (2019) ("If one possible interpretation of a statute would cause some redundancy and another interpretation would avoid redundancy, that difference in the two interpretations can supply a clue as to the better interpretation of a statute.") Courts generally hold that statutory words connoting quantity or proportion are not ambiguous. (*See Rimini St.* at 879-80 (Finding that "full costs" include *all* costs and are synonymous with "entire" and "100 percent") (emphasis added). Accordingly, while PHMSA may have some discretion in defining when a pipeline is "entirely" replaced, the Agency likely does not have authority to determine that replacing multiple portions of a pipeline—such as 2 miles in a 5-mile segment—constitutes an "entire" replacement.

6 inches or greater.[30] Consistent with the congressional mandate in Section 4 of the 2011 Act,[31] the Agency only referenced transmission lines in discussing the applicability of the rule in the NPRM and analyzing the potential impact in the Preliminary Regulatory Impact Analysis (PRIA).[32]

In their written comments, the Liquid Pipeline Associations asked PHMSA to clarify in an exception that the rupture mitigation valve installation requirements would not apply to gathering lines.[33] The Liquid Pipeline Associations explained that the plain language in the 2011 Act supported an exception for gathering lines, and that there was nothing in the record to support the conclusion that requiring rupture mitigation valves on these lines, which tend to be regulated on a segmented basis, would be economically, technically, and operationally feasible.[34]

Despite the absence of any prior statements to that effect, the Agency's presentation to the Committee indicated that the rupture mitigation valve requirements would apply to gathering lines.[35] However, PHMSA expressed a willingness to provide an exception for regulated rural gathering lines that did not cross a commercially-navigable body of water or a water source establishing an HCA.[36] Other than presenting summary data on regulated gathering line mileage installed in prior years, the Agency did not provide any specific data to the LPAC on the costs, benefits, or other impacts of applying the rule to gathering lines.[37]

The Liquid Pipeline Associations reiterated their strong opposition to applying the rupture mitigation valves to gathering lines during the public comment period. After briefly summarizing the concerns raised in its written comments, GPA Midstream noted that Oak Ridge National Laboratories (Oak Ridge) did not consider gathering lines as part of the study that PHMSA commissioned following the 2011 Act, and that none of the twelve hazardous liquid pipeline incidents that the Agency referenced in its LPAC presentation involved gathering lines.[38] GPA Midstream and API both stated that the public did not have an adequate opportunity to consider the Agency's proposal to limit the applicability of the rupture mitigation valve requirements to gathering lines that cross certain water bodies, which had only been presented that day. GPA Midstream and API also noted that PHMSA had not presented any data demonstrating that the installation of rupture mitigation valves on gathering lines was technically feasible, reasonable, cost-effective, or practicable, and that the LPAC could not consider the merits of the proposal without such data.

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[30] NPRM at 7,164.

[31] 2011 Act § 4, 125 Stat. at 907.

[32] Neither the NPRM nor the Preliminary Regulatory Emphasis Analysis even uses the word "gathering," except to reference titles of other rules or in hyperlink addresses. NPRM at 7,166; PRIA at 7, 44 (Feb. 2020), https://www.regulations.gov/document?D=PHMSA-2013-0255-0006.

[33] GPA Comments at 10-12; API/AOPL Comments at 8-9

[34] GPA Comments at 10; API/AOPL Comments at 8.

[35] LPAC Transcript at 125-26.

[36] *Id. But see* LPAC Transcript at 133 "PHMSA will consider the appropriateness of applying this rulemaking or a separate rulemaking to gathering lines *due to the lack of public notice*." (emphasis added).

[37] *Id.* at 149-50 (noting that roughly 200 miles of gathering lines would be covered under the rule).

[38] *Id.* at 136-137; LPAC Presentation Slides at 29 (https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1119).

Industry LPAC members echoed these concerns, noting that the Agency had not presented adequate data for the Committee to fairly consider the proposal to apply rupture mitigation valves to gathering lines.[39] One industry member further noted that including gathering lines would require PHMSA to reconvene the LPAC to weigh in on regulating gathering lines and revisiting the entire rulemaking.[40] Non-industry LPAC members similarly noted that the lack of public notice created a significant procedural barrier to advancing such a proposal in the current rulemaking proceeding, and the Agency expressed a willingness to address gathering lines in a separate rulemaking.[41] The LPAC ultimately provided a unanimous recommendation to PHMSA along these lines, advising the Agency to consider how the lack of due process affected the appropriateness of applying the rupture mitigation valve requirements to gathering lines in the current rulemaking proceeding.[42]

The Liquid Pipeline Associations agree that PHMSA failed to provide the public with notice of its intent to apply the rupture mitigation valve requirements to gathering lines. There are no references to gathering lines in Section 4 of the 2011 Act, the 2012 Oak Ridge study, the NPRM, or the PRIA. Nor does the record contain any information about the costs, benefits, or other impacts associated with requiring gathering line operators to install rupture mitigation valves, or an explanation from PHMSA as to why that action satisfies the applicable rulemaking requirements in the Pipeline Safety Act.[43]

The Liquid Pipeline Associations further note that the lack of public notice and supporting information and analysis in the record are fundamental flaws that cannot be cured during the remaining phases of this rulemaking proceeding. The Administrative Procedure Act requires "an *exchange* of views, information, and criticism between interested persons and the agency,"[44] and that exchange cannot occur after PHMSA issues the final rule. Public notice and the opportunity

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[39] *Id.* at 147-48 ("[A]s we sit here today, with no economic-benefit analysis, really no discussion in terms of operational or technical feasibility…[W]e have a very formal process, and we've adhered to it and [not] allowing others the opportunity through the notice of proposed rule and other comments, feels like we're circumventing…one of the foundational principles" of the LPAC process.) *See also* LPAC Transcript at 141-42 ("[Without]…giving members and others an opportunity to review and comment…[it] would be difficult to wrap our arms around the proposal that's sitting on the table.")

[40] *Id.* at 154.

[41] *Id.* at 145-46 (PHMSA offering to remove gathering lines from the rulemaking); LPAC Transcript at 155 (LPAC member representing the public interest noting "the lack of public notice is a huge barrier…[and] I wouldn't be surprised if we end up with an additional rulemaking.")

[42] *Id.* at 178-81.

[43] While the language in Section 4 of the 2011 Act generally supports the proposition that rupture mitigation valves may be necessary for certain transmission pipeline facilities, the same cannot be said for other kinds or categories of pipelines. Indeed, the Agency summarily excluded gas distribution lines from the requirement to install rupture mitigation valves, presumably because those pipelines fall outside the scope of the congressional mandate in Section 4. Nor is there any indication in the record that PHMSA considered the relevant statutory factors or sought to exercise the general rulemaking authority provided in 49 U.S.C. § 60102(a)-(b) in an effort to require the installation of rupture mitigation valves on gathering lines. *See Comcast Corp. v. FCC*, 600 F.3d 642, 648 (D.C. Cir. 2010) (an agency must demonstrate that a regulatory proposal will advance its mission as delegated by Congress); *Michigan v. EPA*, 576 U.S. 743, 750 (2015) ("Federal administrative agencies are required to engage in 'reasoned decisionmaking.' . . . Not only must an agency's decreed result be within the scope of its lawful authority, but the process by which it reaches that result must be logical and rational. . . . It follows that agency action is lawful only if it rests 'on a consideration of the relevant factors.'") (quoting *Allentown Mack Sales & Service, Inc. v. NLRB*, 522 U.S. 359, 374 (1998) and *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29 (1983))

[44] *Home Box Office, Inc. v. FCC*, 567 F.2d 9, 35 (D.C. Cir. 1977) (emphasis added). *See* 5 U.S.C. § 553(c).

to comment must occur before the Agency prescribes a regulation with the force and effect of law to be meaningful.[45] For these reasons, the Liquid Pipeline Associations ask the Agency to provide an exception from the rupture mitigation valve installation requirements for gathering lines in the final rule.[46]

iii. Low-Stress and Non-HCA Pipelines

In the NPRM, PHMSA proposed to amend § 195.258 to require the installation of rupture mitigation valves on certain pipelines 6 inches in diameter or greater.[47] In their written comments, the Liquid Pipeline Associations asked PHMSA not to apply the rupture mitigation valve requirements to low-stress pipelines with a maximum operating pressure that produces a stress level of 30 percent or less of SMYS, explaining that these lines are not likely to experience in-service ruptures.[48] The Liquid Pipeline Associations also asked PHMSA to limit the rupture mitigation valve requirements to pipelines that could affect HCAs, which are the areas where the installation of rupture mitigation valves will create the greatest public safety benefit.

The Agency stated in its presentation to the LPAC that rupture mitigation valves should be required for low-stress pipelines, which are capable of experiencing ruptures.[49] PHMSA also stated that rupture mitigation valves could minimize the consequence of leaks on low-stress lines. The Agency did not support limiting the installation of rupture mitigation valves to HCAs, which PHMSA stated would exclude certain waterways and other areas that might warrant protection.[50]

Following PHMSA's presentation, the LPAC voted unanimously to approve a recommendation that the Agency consider providing an exception for low-stress pipelines that operate at less than 30 percent of SMYS in light of the cost-benefit concerns and need to maintain the integrity of the rule.[51] During a subsequent portion of the meeting, the LPAC also unanimously recommended that the Agency revise the rule to clarify that that the installation of rupture mitigation valves for pipeline replacements in non-HCA locations would only be required on an opportunistic basis, *i.e.*, if the replacement project involves the installation of a valve.[52]

The Liquid Pipeline Associations continue to support providing an exception from the rupture mitigation valve requirements for low-stress pipelines. While the Agency noted that these lines are capable of experiencing ruptures, the authors of the leading study on the issue only

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[45] *Home Box Office* at 35-36 ("[A] dialogue is a two-way street: the opportunity to comment is meaningless unless the agency responds to significant points raised by the public.") *See also MCI Worldcom, Inc. v. FCC*, 209 F.3d 760, 765 (D.C. Cir. 2000) (An agency is obliged to respond to comments "that can be thought to challenge a fundamental premise" of a rule).

[46] *Carlson v. Postal Regulatory Cmm'n*, 938 F.3d 337, 351 (D.C. Cir. 2019) (If an agency would have adopted unchallenged portion of a rule absent the challenged provisions and the unchallenged portion can function sensibly without them, the challenged portions should be severed, leaving the unchallenged portion intact).

[47] NPRM at 7,179.

[48] GPA Comments at 12-15; API/AOPL Comments at 9-11. *See, e.g.*, 49 C.F.R. § 192.941(a) (establishing a low-stress threshold for gas pipeline integrity assessments at 30% SMYS); ASME B31.8, § 841.32 (indicating a low-stress threshold of 30% SMYS).

[49] LPAC Transcript at 124.

[50] *Id.* at 125-26, 135.

[51] *Id.* at 179.

[52] *Id.* at 257.

identified seven instances where a pipeline operating at pressure below 20 percent of SMYS ruptured from 1990 through the early 2010s.[53] Furthermore, the authors noted that most of those ruptures occurred on vintage electric resistance welded (ERW) pipe that was experiencing selective seam corrosion. The authors do not indicate in the report that the installation of rupture mitigation valves would have minimized the consequences of these pipeline failures. Nor does the occurrence of seven ruptures in more than 20 years contradict the well-established principle that the primary failure mechanism for low-stress pipelines is a leak rather than a rupture.

The Liquid Pipeline Associations recognize that the definition of low-stress pipeline in § 195.2 uses a 20-percent-or-less-of-SMYS threshold, and that other exceptions in Part 195 for low-stress pipelines incorporate that definition. For consistency, the Liquid Pipeline Associations suggest that PHMSA add a similar exception from the rupture mitigation valve requirements for low-stress pipelines. The Liquid Pipeline Associations also support the LPAC's recommendation to use an opportunistic approach in requiring rupture mitigation valves for pipeline replacements in non-HCA locations. The Liquid Pipeline Associations agree that rupture mitigation valves should only be required in these situations if the replacement requires the installation of a new valve.

iv. Manual Valves or Equivalent Technology

In the NPRM, PHMSA proposed to add a provision that would allow operators to install a manual valve or use equivalent technology instead of a rupture mitigation valve by following a 90-day-notification-and-no-objection process.[54] In their written comments, the Liquid Pipeline Associations asked PHMSA to clarify the process and limit the amount of additional time that the Agency is afforded to conduct a post-notification review to a one-time extension of no more than 45 days.[55]

The Agency responded to some of these comments during the LPAC meeting. Specifically, PHMSA expressed a willingness to clarify the notification-and-no-objection process and offered additional information on the factors that would be relevant in reviewing requests for manual valves, such as closure time, reliability, adequate access to communications and power, and surrounding terrain and population density.[56] Following the Agency's presentation, the LPAC adopted a unanimous recommendation that PHMSA consider revising the notification-and-no-objection process, including by incorporating changes that would align with the comparable provision for gas pipelines in 49 C.F.R. § 192.18.[57]

The Liquid Pipeline Associations support clarifying the process for using manual valves or equivalent technologies in the rupture mitigation valve requirements. Operators should be allowed to install manual valves or use an equivalent technology if a letter of objection is not received within the initial 90-day review period. The Liquid Pipeline Associations continue to support including a provision that authorizes a one-time extension of up to 45 days if PHMSA needs

[53] Study of Pipelines that Ruptured While Operating at a Hoop Stress Below 30% SMYS, Michael Rosenfeld and Robert Fassett, Pipeline Pigging and Integrity Management Conference, Houston, TX (Feb. 2013)
[54] NPRM at 7,186, 7,188.
[55] GPA Comments at 13; API/AOPL Comments at 10.
[56] LPAC Transcript at 131.
[57] *Id.* at 123, 178.

additional time to review an operator's notification and supporting information. Operators should be allowed to install manual valves or use an equivalent technology if the Agency does not respond with a letter of objection during the additional 45-day period.

v. Compliance Deadline

In the NPRM, PHMSA proposed to apply the rupture mitigation valve installation requirements to new pipeline systems and certain replacements of existing pipeline systems 12 months after the effective date of the final rule.[58] The Liquid Pipeline Associations asked the Agency to increase that deadline to 24 months in their written comments to account for the acquisition of valves, land rights, permits, and other activities needed to achieve compliance.[59]

In its presentation to the LPAC, PHMSA argued in favor of retaining the 12-month effective date as proposed in the NPRM.[60] The Agency stated that the final rule would not go into effect until 6 months after publication in the *Federal Register*; therefore, operators would have 18 months from the date of publication to comply with rupture mitigation valve requirements under the proposed 12-month effective date. In light of concerns raised by non-industry LPAC members, the Committee made a unanimous recommendation that PHMSA consider reducing the implementation timeframe to between 12 and 18 months.[61]

The Liquid Pipeline Associations continue to believe that a 24-month implementation date for the rupture mitigation installation requirements is appropriate. However, the compliance date included in the final rule can be adjusted to reflect any delay in the overall effective date of the final rule between publication in the *Federal Register* and adoption in the Code of Federal Regulations. In the event that the Agency adopts an earlier implementation date, the Liquid Pipeline Associations believe that a notification process allowing the deadline to be extended in appropriate cases must be included to account for procurement and other commercial issues as well as permitting and other requirements.

B. Proposed Final Rule Language

§ 195.259 Valves: Rupture Mitigation.

(a) *Scope*. The requirements in this section do not apply to:

(1) Offshore pipelines,

(2) Gathering lines,

(3) Low-stress pipelines, or

(4) Existing pipelines unless:

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[58] NPRM at 7,186.
[59] GPA Comments at 9; API/AOPL Comments at 7-8.
[60] LPAC Transcript at 132.
[61] *Id.* at 179.

(i) 2 or more contiguous miles of pipe is replaced during a 24-month period; and

(ii) If the replaced pipe is not located in a high consequence area as defined in § 195.450, the operator is installing a new valve as part of the replacement.

(b) *Installation*. Except as provided in paragraph (a) of this section, each pipeline segment that is:

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

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

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 this section.

(c) *Notification*. To install a manual valve or use an equivalent technology under 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.

(d) *Authorization*. The installation of a manual valve or use of an equivalent technology is authorized under this section:

(i) 91 days after PHMSA receives the notification required under paragraph (c) 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 45-day time period is needed to complete the review.

(ii) In cases where the additional 45-day time period is needed to complete the review, 136 days after PHMSA receives the notification required under paragraph (c) of this section, unless the operator receives a letter from the Associate Administrator for Pipeline Safety objecting to the proposed installation or use.

IV. Valve Spacing

This section includes supplemental comments and proposed final rule language for the rupture mitigation valve installation requirements. As previously discussed, the Liquid Pipeline Associations are requesting that PHMSA consolidate any maximum valve spacing intervals into a single provision and provide a 25 percent tolerance HVL pipelines. The Liquid Pipeline Associations also ask that the Agency allow operators to seek approval of alternative spacing intervals in appropriate cases.

A. Comments

In the NPRM, PHMSA proposed to add new maximum spacing intervals to § 195.260 for pipelines transporting HVLs (7.5 miles), pipelines that could affect HCAs (15 miles), and all other pipelines (20 miles).[62] PHMSA also proposed to reference the provision in the integrity management regulations that requires consideration of EFRDs and impose a new 7.5-mile maximum valve spacing interval from the endpoint of any HCA pipeline segments.[63] The Agency proposed to amend the requirements for valves at water crossings that are more than 100-feet wide from high-water mark to high-water mark by adding a provision for the installation of actuators or other control equipment that could be impacted by flood conditions and a 1-mile limitation for valves protecting multiple crossings.[64]

In their written comments, the Liquid Pipeline Associations asked the Agency to consolidate the maximum valve spacing intervals into a single provision and make other changes to align with comparable Canadian standards. These changes included increasing the maximum valve spacing interval for HVL pipelines from 7.5 miles to 10 miles and adopting a generally applicable 25 percent tolerance for each of the maximum valve spacing intervals.[65] The Liquid Pipeline Associations also asked the Agency to eliminate the 7.5-mile maximum valve spacing interval from the endpoint of HCA segments and allow operators to seek approval for alternative valve spacing distances in appropriate situations. The Liquid Pipeline Associations asked PHMSA

[62] NPRM at 7,186.
[63] *Id.* at 7,189.
[64] *Id.* at 7,186.
[65] GPA Comments at 18-20; API/AOPL Comments at 11-14. *See* CAN/CSA Z662-19, § 4.5. In their written comments, the Liquid Pipeline Associations expressed support for the existing functional approach and opposition to adopting numerical thresholds for valve spacing, which create additional pipeline security concerns and environmental impacts, such as filling in wetlands during clearing and grading activities as part of the installation process. The Liquid Pipeline Associations continue to support these positions, but are focusing the supplemental comments in this letter on the LPAC's recommendation in favor of adding maximum valve spacing intervals to Part 195.

clarify the 1-mile limitation on valve spacing for multiple water crossings and specify that the scope of limitations for placing valves in proximity to water crossings in § 195.260(e) is based on a 100-year flood plain.

The Agency responded to some of the Liquid Pipeline Associations' written comments during the LPAC meeting. PHMSA expressed a willingness to consider adopting a 25 percent tolerance for valve spacing on HVL lines (7.5 miles) and HCA lines (15 miles) and adding a notification requirement to allow operators to obtain relief from valve spacing requirements on a case-by-case basis.[66] The Agency agreed that the 7.5-mile limitation for HCA segment endpoints was unnecessary and expressed its intent to clarify the valve spacing limitations for multiple water crossings, including by adding a reference to the 100-year flood plain.[67] Following PHMSA's presentation, the LPAC approved a unanimous recommendation that the Agency authorize a 25 percent tolerance to the maximum spacing interval for HVL lines and create a notification process for obtaining approval of alternative spacing intervals in appropriate cases.[68] The LPAC also recommended that the Agency specify that the 100-year flood plain applies in complying with the valve spacing requirements for water crossings that are more than 100 feet (30 meters) wide from high-water mark to high-water mark.

The Liquid Pipeline Associations continue to support consolidating any new maximum valve spacing intervals into a single provision. The Liquid Pipeline Associations also support the 7.5-mile maximum valve spacing interval for HVL pipelines, provided that the 25 percent tolerance is authorized for cases when the operator determines that the installation of a valve at a particular location is impracticable and keeps a record of that determination for the useful life of the pipeline. Finally, the Liquid Pipeline Associations support the LPAC's recommendation that the Agency allow operators to seek approval for alternative valve spacing intervals in appropriate cases and clarify the requirements for the placement of valves at water crossings.

B. Proposed Final Rule 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 as defined in § 195.450.

(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.

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66 LPAC Transcript at 189, 91.
67 *Id.* at 191-93.
68 *Id.* at 221-24.

* * * * *

(e) On each side of one or more adjacent, well-defined water crossings that are more than 100 feet (30 meters) wide from high-water mark to high-water mark, provided:

(1) the valves must be installed at locations outside of the 100-year flood plain or equipped with actuators or other equipment that is not impacted by flood conditions, and

(2) the maximum spacing interval between valves that protect multiple adjacent water crossings cannot exceed 1 mile in length,

unless the Administrator finds under paragraph (h) of this section that the installation of a valve is not necessary in a particular case.

* * * * *

(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) 7.5 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 all other pipeline segments.

(4) The maximum valve spacing intervals in this paragraph for HVL pipelines 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) Retains 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) Including the information required to demonstrate that the installation of a valve is necessary in a particular case.

(4) The Associate Administrator shall decide whether the installation of a valve is necessary in a particular case within 90 days of receiving the notification required under this paragraph of this section, unless the Associate Administrator notifies the operator 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 the final decision.

* *

V. Operations and Maintenance Manual

This section includes supplemental comments and proposed final rule language for the operations and maintenance manual requirements.

A. Comments

In the NPRM, PHMSA proposed to add several new provisions to § 195.402, including detailed requirements for conducting investigations and analyses of pipeline accidents and failures as well as supplemental requirements for failures or accidents involving ruptures or the closure of rupture mitigation valves.[69] Another provision included a requirement for operators with rupture mitigation valves to identify ruptures within 10 minutes of initial notification. Other provisions included detailed requirements for establishing and maintaining communication with first responders, identifying events that may require notification to first responders, and coordinating and sharing information with first responders during releases and emergencies.

In their written comments, the Liquid Pipeline Associations noted that the proposed requirements for conducting investigations of pipeline accidents and failures should be stated more clearly and succinctly and in a manner that provide operators with greater flexibility.[70] The Liquid Pipeline Associations opposed the senior executive signature requirement for post-rupture analyses as unnecessary and unduly burdensome. The Liquid Pipeline Associations opposed the arbitrary 10-minute rupture identification deadline and noted that the provisions for interacting with public safety answering points did not account for pipelines that are located in areas where there is no direct access to 9-1-1 emergency call centers. For these locations, the Liquid Pipeline Associations suggested that other public officials, such as local fire and police departments, should be identified as a substitute.

PHMSA addressed some of the Liquid Pipeline Associations' comments during the LPAC meeting. The Agency opposed eliminating the senior executive official certification requirement but agreed that the 10-minute rupture identification deadline could be eliminated, provided that

[69] NPRM at 7,187-88.

[70] GPA Comments at 21-22; API/AOPL Comments at 15-16.

the rupture mitigation valve shutoff deadline was reduced from 40 to 30 minutes.[71] PHMSA agreed to modify the proposed regulations to address circumstances where a pipeline is not located in a 9-1-1 area as well.[72] The LPAC's recommendations generally supported the Agency's proposals on these issues.[73]

The Liquid Pipeline Associations continue to support streamlining the changes to the written procedures that must be included in the manual for performing operations and maintenance activities and handling abnormal operations and emergencies. The post-incident lessons learned language can be condensed and clarified, providing greater clarity and flexibility to operators as they attempt to improve their safety procedures. The Liquid Pipeline Associations still oppose the senior executive official signature requirement for post-incident analyses, which is unnecessary and unduly burdensome. The Liquid Pipeline Associations support eliminating the 10-minute rupture identification as arbitrary and lacking any technical justification. The Liquid Pipeline Associations continue to support revising the final rule to address circumstances where a pipeline is not located in a 9-1-1 area.

B. Proposed Final Rule Language

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

* * * * *

(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 rupture occurs:

(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:

[71] LPAC Transcript at 231-32, 249. *See* LPAC Transcript at 232-33 (noting that previous discussion slides were marked Part 192 but should have referred to Part 195).
[72] *Id.* at 262-63, 72-74.
[73] *Id.* at 254-55, 58-59.

(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 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.

(iv) Preparing a final version of the analysis required under paragraph (c)(6)(i) of this section after completing the investigation that is 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), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, as well as appropriate local emergency coordinating agencies, 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), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, 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 § 195.259 or subject to the requirements in § 195.418 must establish procedures that specify the sources of information, operational factors, and other criteria that personnel use for purposes of rupture identification.

* * * * *

(7) Notifying the appropriate public safety answering point (9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, 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.

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VI. Operations Requirements for Rupture Mitigation Valves

This section includes supplemental comments and proposed final rule language for the operations requirements for rupture mitigation valves.

A. Comments

In the NPRM, PHMSA proposed to add new operations requirements for rupture mitigation valves in 49 C.F.R. § 195.418.[74] The new requirements included a 7-day deadline for ensuring the operability of a rupture mitigation valve after a pipeline is placed into service, as well as a 40-minute deadline for shutting off rupture mitigation valves following the point of rupture

[74] NPRM at 7,187–88.

identification. The new requirements also included additional maximum valve spacing intervals and provisions for valve capabilities, methods, and monitoring and operation.

In their written comments, the Liquid Pipeline Associations generally noted that many of the new operations requirements for rupture mitigation valves were duplicative and overly-prescriptive.[75] The Liquid Pipeline Association asked PHMSA to establish clear limitations on the applicability of the requirements, eliminate the additional valve spacing intervals, and allow operators to seek an extension of the 40-minute maximum shutoff time for rupture mitigation valves in appropriate cases.

PHMSA addressed some of these comments during the LPAC meeting. The Agency acknowledged that many of the provisions in the new operations requirements were duplicative and could be revised to improve clarity.[76] PHMSA expressed support for changing the rupture mitigation valve shutoff timeframe by eliminating the 10-minute rupture identification requirement, reducing the overall closure time from 40 minutes to 30 minutes, and allowing manual valves in non-HCA locations to exceed that deadline if the operator submits a notification and demonstrates that installing a rupture mitigation valve is economically, technically, or operationally infeasible.[77] The Agency agreed to clarify that rupture mitigation valve status need not be monitored if the operator can monitor pressure or flows to be able to identify and locate a rupture.[78]

The Liquid Pipeline Associations offered additional public comment on these issues during the LPAC meeting. GPA Midstream and API noted that PHMSA's rupture mitigation shutoff deadline might not be operationally feasible in certain situations, and that valve closures create pressure surges and other cascading effects in hazardous liquid pipeline systems that are not present in gas pipeline systems.[79] AOPL echoed the GPA Midstream and API comments, noting that the Agency needs to accommodate the different risks associated with hazardous liquid and gas pipelines in developing the final rule.[80]

The LPAC offered several unanimous recommendations to PHMSA for modifying the operations requirements for rupture mitigation valves.[81] The LPAC recommended that the Agency eliminate the prescriptive 10-minute rupture identification deadline and require rupture mitigation valves closure as soon as practicable, but no later than 30 minutes, after rupture identification. The LPAC also recommended that PHMSA allow manual valves in remote, non-HCA locations to exceed the 30-minute rupture mitigation closure deadline, if the operator submits a notification and demonstrates that installing an automatic shutoff or remote-control valve is economically, technically, or operationally infeasible.

[75] GPA Comments at 21-24; API/AOPL Comments at 15-18.
[76] LPAC Transcript at 226.
[77] *Id.* at 51.
[78] *Id.* at 194.
[79] *Id.* at 58, 60.
[80] *Id.* at 62-63.
[81] *Id.* at 117, 254-55.

The Liquid Pipeline Associations support the LPAC's recommendation to eliminate the 10-minute rupture identification deadline. The deadline is arbitrary and lacks any technical support in the record. The Liquid Pipeline Associations also support the LPAC's recommendation to reduce the rupture mitigation valve shutoff deadline from 40 minutes to 30 minutes, provided that operators can request a longer deadline for pipelines that use manual valves in remote, non-HCA locations. Accessing these locations, which generally present a very low risk to public safety, within the 30-minute deadline may not be possible in all cases.

The Liquid Pipeline Associations continue to support including a scope provision at the outset of the regulation that limits the operations requirements to rupture mitigation valves, manual valves, or equivalent technology installed or authorized under § 195.259. The Liquid Pipeline Associations remain opposed to including any additional valve spacing provisions in the operations requirements. Any such provisions should be included in the new rupture mitigation valve installation requirements.

B. Proposed Final Rule Language

§ 195.418 Rupture mitigation valves.

(a) *Scope.* The requirements in this section only apply to rupture mitigation valves, manual valves, or equivalent technology that an operator installs or uses to comply with § 195.259.

(b) *Shut-off time.* As soon as practicable, but no later than 30 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 § 195.259 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; and

(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.

(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 an alternative shut-off time from the Associate Administrator for Pipeline Safety under paragraph (b) of this section, an operator must:

(1) Send a notification to PHMSA 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 PHMSA with the information required to demonstrate that compliance with the 30-minute shut-off time in paragraph (b) of this section is economically, technically, or operationally infeasible and include an alternative shut-off time for review and 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 the final decision.

* *

VII. Valve Maintenance

This section includes supplemental comments and proposed final rule language for the valve maintenance requirements.

A. Comments

In the NPRM, PHMSA proposed to amend the valve maintenance requirements in § 195.420 by requiring partial operation of rupture mitigation valves as part of semi-annual inspections.[82] PHMSA also proposed, among other things, to require control room management (CRM)-related activities as part of valve maintenance, and additional activities for manually- or locally-operated rupture mitigation valves.

In their written comments, the Liquid Pipeline Associations stated that the references to the CRM requirements should be eliminated as unnecessary, and that the proposed regulation should be revised to acknowledge that an operator could obtain an alternative rupture mitigation shutoff deadline with Agency approval.[83] The Liquid Pipeline Associations further stated that the proposed regulation included a 6-month deadline for repair or replacement of a rupture mitigation valve that may not be achievable, including in cases where parts are unavailable or where access to the location of repair or replacement is difficult or restricted. As an alternative to the proposed 6-month deadline, the Liquid Pipeline Associations suggested that operators be allowed to establish appropriate repair and replacement timeframes in their written procedures. The Liquid Pipeline Associations stated that PHMSA should clarify the provision requiring designation of an alternative valve within 14 calendar days after a finding that a rupture mitigation valve required repair or replacement.

PHMSA responded to some of these comments during the LPAC meeting.[84] The Agency agreed that the references to the CRM requirements could be eliminated. While stating that the 7-day timeframe for identifying alternative shutoff measures and 6-month timeframe for valve repair

[82] NPRM at 7,188–89.
[83] GPA Comments at 25-31, API/AOPL Comments at 18-20.
[84] *See* LPAC Transcript at 225-35.

or replacement should be retained, the Agency agreed to consider adding a notification provision that would allow operators to extend those deadlines.[85] PHMSA also agreed to clarify that alternative valves are not required to comply with valve spacing requirements.

The LPAC provided several unanimous recommendations for the Agency to consider in developing the final rule.[86] Specifically, the Committee recommended that the CRM references be deleted, that PHMSA clarify that the annual drill requirement only applies to manually-operated valves, and that the Agency acknowledge that a 25 percent valve closure would be sufficient for purposes of the response time validation drill. The LPAC further recommended that operators be allowed to use a notification process to extend the timeframes for repair or replacement of rupture mitigation valves and designation of alternative valves, and that the Agency consider extending the 6-month deadline for repairs or replacements to 12 months. The Liquid Pipeline Associations generally support each of these recommendations.

B. Proposed Final Rule 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, manual valve, or equivalent technology installed or authorized under § 195.259 as part of that inspection.

* * * * *

(d) 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 30-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 30 minutes (or the authorized alternative response time) following rupture identification.

[85] *Id.* at 228.
[86] *Id.* at 254-55.

(2) A mainline valve within each pipeline system must be randomly selected for an annual 30-minute or authorized alternative total response time validation drill to 25 percent closure that simulates reasonable 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 30-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 as soon as practicable but not later than 12 months after the drill, and implement alternative valve shut-off measures in accordance with paragraph (f) of this section.

(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 implement the following remedial measures to correct any rupture mitigation valve, manual valve, or equivalent technology installed or authorized under § 195.259 that is found to be inoperable or unable to maintain effective shut-off:

(1) Repair or replace the valve as soon as practicable, but within 12 months of discovery.

(2) If an alternative valve is already installed at the pipeline segment, designate an alternative valve within 7 days of discovery.

(3) An operator may extend the deadlines provided in this paragraph by sending a notification and adequate supporting justification to PHMSA 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.

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VIII. Integrity Management Preventative and Mitigative Measures

A. Comments

In the NPRM, PHMSA proposed to amend the preventive and mitigative measures provision in the integrity management requirements for EFRDs.[87] Specifically, the Agency proposed changes to § 195.452(i)(4)(i) that appeared to require that EFRDs comply with the provisions for rupture mitigation valves if applicable.

In their written comments, the Liquid Pipeline Associations noted that many of the proposed changes were unnecessary because EFRDs would be considered rupture mitigation valves at the time of installation.[88] The Liquid Pipeline Associations suggested that the language be clarified by noting that EFRDs installed under the IM regulations must meet the applicable requirements in Part 195 for rupture mitigation valves. Although the Committee did not offer any specific recommendations in that regard, PHMSA acknowledged the appropriateness of these comments during the LPAC meeting.[89]

B. Proposed Final Rule Language

§ 195.452 Pipeline integrity management in high consequence areas.

* * * * *

(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.

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[87] NPRM at 7,189.
[88] GPA Comments at 33-34, API/AOPL Comments at 23.
[89] LPAC Transcript at 173-74.

IX. Conclusion

The Liquid Pipeline Associations appreciate the opportunity to submit additional comments in this rulemaking proceeding. Please feel free to contact Dave Murk at API, Andy Black at AOPL, or Matt Hite at GPA Midstream if you have questions or concerns.

Respectfully submitted,

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