DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 192 and 195

[Docket No. PHMSA–2013–0255; Amdt. Nos. 192–130; 195–105]

RIN 2137–AF06

Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations applicable to most newly constructed and entirely replaced onshore gas transmission, Type A gas gathering, and hazardous liquid pipelines with diameters of 6 inches or greater. In the revised regulations, PHMSA requires operators of these lines to install rupture-mitigation valves (*i.e.,* remote-control or automatic shut-off valves) or alternative equivalent technologies, and establishes minimum performance standards for those valves' operation to prevent or mitigate the public safety and environmental consequences of pipeline ruptures. This final rule establishes requirements for rupture-mitigation valve spacing, maintenance and inspection, and risk analysis. The final rule also requires operators of gas and hazardous liquid pipelines to contact 9–1–1 emergency call centers immediately upon notification of a potential rupture and conduct post-rupture investigations and reviews. Operators must also incorporate lessons learned from such investigations and reviews into operators' personnel training and qualifications programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications. PHMSA is promulgating these regulations in response to congressional directives following major pipeline incidents where there were significant environmental consequences or losses of human life. The revisions are intended to achieve better rupture identification, response, and mitigation of safety, greenhouse gas, and environmental justice impacts.

DATES: The effective date of this final rule is October 5, 2022.

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SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of the Regulatory Action

This final rule is the culmination of a decade-long PHMSA rulemaking effort responding to congressional mandates, National Transportation Safety Board (NTSB) recommendations, and Government Accountability Office (GAO) recommendations to revise the Federal Pipeline Safety Regulations at 49 Code of Federal Regulations (CFR) parts 192 and 195 to prevent the catastrophic loss of life, property damage, and environmental harm experienced from ruptures on large-diameter hazardous liquid and natural gas pipelines, such as those that occurred near Marshall, MI, and San Bruno, CA, in 2010.

This final rule codifies a suite of design and performance standards prescribing the installation, operation, and spacing of rupture-mitigation valves (RMV) or alternative equivalent technologies on most new or entirely replaced, onshore, large-diameter (6 inches or greater), gas transmission, Type A gas gathering, and hazardous liquid pipelines.[1] The final rule also requires operators of all gas and hazardous liquid pipelines to modify their emergency plans to ensure immediate and direct contact of 9–1–1 emergency call centers, or coordinating government officials, on notification of a potential rupture. PHMSA expects this final rule's regulatory amendments will ensure operators of pertinent gas and hazardous liquid pipelines take prompt identification, isolation, and mitigation actions with respect to unintentional or uncontrolled, large-volume releases of gas or hazardous liquids during a pipeline rupture. The safety enhancements in this final rule, therefore, are expected to improve public safety, reduce threats to the environment (including, but not limited to, reduction of greenhouse gas (GHG) emissions released during ruptures of natural gas pipelines), and promote environmental justice for minority populations, low-income populations, or other underserved and disadvantaged communities.

Recent pipeline ruptures with catastrophic consequences underscore the importance of prompt identification, isolation, and mitigation actions in reducing the amount of product released—and by extension, the loss of life, property damage, and environmental harm—from ruptures on hazardous liquid and natural gas pipelines. One such rupture occurred on July 25, 2010, in Marshall, MI, resulting in a release of approximately 800,000 gallons of crude oil into the Kalamazoo River and approximately $1 billion in property and environmental damages.[2] The operator, Enbridge Energy, LP (Enbridge), took 18 hours to confirm the

[1] For the purposes of this final rule, references to diameter are to the outside diameter of the pipe. Similarly, subsequent references in this final rule to gas transmission, Type A gas gathering, and hazardous liquid pipelines will, for brevity, generally omit the qualifications (onshore, 6-inch diameter) appearing in the statement of the final rule's scope above. Lastly, references within this final rule to ''hazardous liquid pipelines'' will, unless otherwise stipulated, include carbon dioxide pipelines because both hazardous liquid and carbon dioxide pipelines are subject to 49 CFR part 195 requirements.

[2] NTSB, Accident Report PAR–12/01, ''Enbridge Incorporated: Hazardous Liquid Pipeline Rupture and Release; Marshall, MI: July 25, 2010'' (July 10, 2012), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1201.pdf.*

pipeline rupture following the initial alarms received by the control room operators. Once Enbridge confirmed the rupture, the failed segment was immediately isolated using installed remote-control shut-off valves (RCV).

Another rupture occurred on September 9, 2010, in San Bruno, CA, when a gas transmission pipeline ruptured, causing an explosion that killed 8 people, sent 51 other people to the hospital, destroyed 38 homes and damaged 70 others, and caused the evacuation of approximately 300 homes. According to the NTSB report on that incident,[3] the initial 9–1–1 notification call by the public was made within one minute of the rupture, which occurred at 6:11 p.m. The response crew assembled to operate valves and isolate the rupture did not reach the first valve site until 7:20 p.m. According to the California Public Utilities Commission (CPUC) report on the incident, the operator, Pacific Gas and Electric (PG&E), did not confirm that the incident was a pipeline rupture until 7:25 p.m., when PG&E employees in the field, at dispatch, and in the company's supervisory control and data acquisition (SCADA) [4] center confirmed that a PG&E gas transmission line had failed.[5] After multiple valve closures, PG&E isolated the ruptured pipeline segment at 7:46 p.m., 95 minutes after the rupture initiated.[6] This delay in closing the valves allowed the fire to burn unabated and hampered emergency response efforts.

These rupture events highlight the need for more robust protections in the Federal Pipeline Safety Regulations for identifying, isolating, and mitigating catastrophic pipeline failures. First, there is a need for better and more timely rupture isolation and mitigation equipment and methods. PG&E's failure to close isolation valves rapidly after the rupture at San Bruno diminished its ability to mitigate the consequences of the failure, allowing the fire to burn unabated for 95 minutes following the initial rupture, with firefighting operations continuing for an additional 2 days after the rupture occurred. Second, there is need for operators to identify promptly that a rupture has occurred and respond quickly to mitigate its consequences. Enbridge had remote-control isolation valves installed on its ruptured oil pipeline at the time the spill occurred near Marshall, MI, but its failure to confirm and respond to the rupture promptly rendered that technology essentially useless.

After these spill events, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act; Pub. L. 112–90) was enacted. The legislation contained several mandates to improve pipeline safety. In particular, PHMSA is required to issue regulations requiring the use of automatic shut-off valves (ASV) or RCVs, or equivalent technology, on newly constructed or replaced gas transmission and hazardous liquid pipeline facilities. *See* 49 U.S.C. 60102(n). That statutory mandate was subsequently revisited, establishing a new deadline for PHMSA to issue a final rule (*see* 49 U.S.C. 60102 note).

In developing this final rule, PHMSA considered NTSB safety recommendations following the PG&E incident; GAO recommendations on the ability of operators to respond to commodity releases in high-consequence areas (HCA); [7] technical reports commissioned by PHMSA on valves and leak detection; [8] [9] comments received on related topics through advance notices of proposed rulemaking (ANPRM) and the notice of proposed rulemaking (NPRM) published in February 2020; [10] and feedback from members of the public, environmental advocacy organizations, State pipeline safety regulators, and industry representatives during Gas Pipeline Advisory Committee and Liquid Pipeline Advisory Committee meetings.

B. Summary of the Major Provisions of the Regulatory Action

This final rule prescribes installation and spacing requirements for ASVs and RCVs (collectively, rupture-mitigation valves, or RMVs) as well as for alternative equivalent technology. The requirements apply to most newly constructed, or entirely replaced, onshore pipelines with diameters of 6 inches or greater, including natural gas transmission pipelines, Type A gas gathering pipelines, and hazardous liquid pipelines (including certain regulated hazardous liquid gathering pipelines). In this final rule, PHMSA has defined an ''entirely replaced'' pipeline as a pipeline that has 2 or more miles being replaced with new pipe within any stretch of 5 contiguous miles within any 24-month period.

The rule also defines ASVs and RCVs as RMVs. PHMSA did not identify specific technologies that operators might use as alternative equivalent technologies for the purposes of this rulemaking, but PHMSA is requiring that such alternative technologies meet the performance standard for RMVs, to include the ability to immediately enable isolation of a rupture—in 30 minutes or less, measured from an operator's identification of a rupture after notification of a potential rupture.

Operators of pipelines subject to the requirements of this final rule may request to install alternative equivalent technologies if they can demonstrate within a notification for PHMSA review that site-specific installation of an alternative equivalent technology would provide an equivalent level of safety to an RMV. Those notifications must be submitted in advance of installation of that technology, and must demonstrate an equivalent level of safety by reference to technical and safety factors including, but not limited to, the following: Design, construction, maintenance, and operating procedures; technology design and operating characteristics such as operation times (closure times for manual valves); service reliability and life; accessibility to operator personnel; nearby population density; and potential consequences to the environment and the public. Further, should an operator request use of manual valves as an alternative equivalent technology, the notification submitted to PHMSA must also demonstrate the economic, technical, or operational infeasibility of installation of an RMV by reference to

[3] NTSB, Accident Report PAR–11/01, ''Pacific Gas and Electric Company; Natural Gas Transmission Pipeline Rupture and Fire; San Bruno, CA; September 9, 2010'' (Aug. 30, 2011), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf.*

[4] Most pipeline operators utilize a SCADA system to run their operations. These are computer-based systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility. *See* 49 CFR 192.3 and 195.2.

[5] CPUC, ''Sept. 9, 2010 PG&E Pipeline Rupture in San Bruno, CA'' (Jan. 12, 2012), *https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_website/Content/Safety/Natural_Gas_Pipeline/News/AgendaStaffReportreOIIPGESanBrunoExplosion.pdf.*

[6] The CPUC also noted that the backfeed to the line and the gas feeds to a related distribution system were not closed until 7:52 p.m. and 11:32 p.m., respectively.

[7] GAO, ''Pipeline Safety: Better Data and Guidance Needed to Improve Pipeline Operator Incident Response'' (Jan. 2013), *https://www.gao.gov/assets/660/651408.pdf.* An HCA, briefly, is an area with higher population density or contains an area of cultural significance or where people would congregate at a certain frequency (*e.g.,* churches, playgrounds, schools, hospitals, etc.). *See* § 192.903.

[8] Oak Ridge National Laboratory (ORNL), ORNL/TM–2012/411, ''Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves and Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety'' (Oct. 31, 2012), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/16701/finalvalvestudy.pdf.*

[9] Kiefner and Associates, Inc., Report No. 12–173, ''Leak Detection Study—DTPH56–11–D–000001'' (Dec. 10, 2012), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/16691/leak-detection-study.pdf.*

[10] 85 FR 7162 (Feb. 6, 2020) (NPRM).

factors such as access to communications and power; terrain; prohibitive cost; labor and component availability; ability to secure required land access rights and permits; and accessibility to operator personnel for installation and maintenance.

For regulated rural hazardous liquid gathering pipelines,[11] at this time, PHMSA is requiring the installation of RMVs or alternative equivalent technology only where such pipelines cross bodies of water more than 100 feet in width from high water mark to high water mark. For hazardous liquid pipelines in general, this final rule establishes valve spacing thresholds both within and outside of HCAs and provides valve spacing limits for highly volatile liquid (HVL) pipelines in populated areas. PHMSA has recently issued a final rule in a separate rulemaking that will update its regulations that affect all types of gas gathering pipelines.[12]

For gas transmission and Type A gas gathering pipelines, the RMV or alternative equivalent technology installation requirements will not apply if the pipeline segment is in a Class 1 or Class 2 location and has a potential impact radius (PIR) less than or equal to 150 feet. PHMSA understands that the lower operating pressures characteristic of Type B gas gathering pipelines involve risk profiles comparable to the Type A gas gathering pipelines exempted from the final rule's installation and operational requirements. Therefore, the final rule similarly exempts Type B gas gathering pipelines from the RMV or alternative equivalent technology installation requirements. The final rule also exempts Type C gas gathering lines from those requirements, as that designation was established by the Gas Gathering final rule—which was published well after the publication of the NPRM for this rulemaking.

Additionally, for each gas pipeline whose operator, in response to a class location change, chooses to replace 2 or more miles of pipe within a contiguous 5-miles to meet the maximum allowable operating pressure (MAOP) requirements of the new class location, the operator would be required to install or otherwise modify existing valves as necessary to comply with the valve spacing requirements and rupture mitigation requirements of this final rule.[13] The final rule provides operators replacing smaller pipeline segments following a change in class location more flexibility: Operators replacing between 1,000 feet and 2 miles may either install RMVs, or they may automate existing valves with automatic or remote-control actuators and pressure sensors (with a maximum spacing of 20 miles). And the final rule's RMV installation and spacing requirements do not apply to those pipe replacements that amount to less than 1,000 feet within any single mile during any 24-month period.

This final rule also establishes Federal minimum safety performance standards for the identification of ruptures, pipeline segment isolation, and other mitigative actions, for pipelines on which RMVs or alternative equivalent technology are installed pursuant to this rulemaking. Relevant new requirements include: (1) A definition of the term ''notification of potential rupture'' to identify signs of an uncontrolled release of a large volume of commodity observed by, or reported to, the operator; (2) establishing written procedures for identifying and responding to a rupture; (3) responding to an identified rupture by closing RMVs or alternative equivalent technology, to provide complete valve shut-off and segment isolation as soon as practicable, but no more than 30 minutes after rupture identification; (4) performing post-event reviews of any incidents/accidents or other failure events involving the closure of RMVs or alternative equivalent technologies to ensure the performance objectives of this rule are met and to apply any lessons learned system-wide; (5) performing maintenance on RMVs and alternative equivalent technology, which includes drills for alternative equivalent technology that is manually or locally operated; and (6) remediation measures for repair or replacement of inoperable RMVs and alternative equivalent technologies, including an RMV or alternative equivalent technology that cannot maintain shut-off, as soon as practicable.

This final rule also requires operators of all gas and hazardous liquid pipelines subject to the emergency planning requirements at §§ 192.615 and 195.402, respectively, to update their emergency response plans to provide for immediate and direct notification of appropriate public safety answering points (9–1–1 emergency call centers) for the communities and jurisdictions in which a rupture is located following the notification of a potential rupture. Similarly, the final rule requires all gas and hazardous liquid pipelines subject to failure investigation requirements at §§ 192.617 and 195.402, respectively, to conduct post-rupture investigations and reviews, and to incorporate lessons learned from such investigations and reviews into their personnel training and qualifications programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

C. Costs and Benefits

Consistent with Executive Order 12866 (''Regulatory Planning and Review''),[14] PHMSA has prepared an assessment of the benefits and costs of this final rule, as well as reasonable alternatives. The Regulatory Impact Analysis (RIA) developed by PHMSA in support of this final rule, and which is available in the rulemaking docket, estimates the annual costs of the rule to be approximately $5.9 million, calculated using a 7 percent discount rate. In the RIA, costs are aggregated by compliance method to estimate total costs, by year, for the baseline and the final rule. The incremental effect of this rulemaking is estimated by taking the difference in total costs relative to the baseline. Costs are then aggregated across all years in the analysis period and annualized. The costs reflect the installation of valves on certain newly constructed and entirely replaced gas and hazardous liquid pipelines, as well as incremental programmatic changes that operators will need to make to incorporate the proposed rupture identification and response procedures.

PHMSA provides a qualitative discussion of the benefits of this rulemaking in the RIA.[15] PHMSA expects this final rule's regulatory amendments will compel operators of

[11] A regulated rural hazardous liquid gathering pipeline is defined in § 195.11 as an onshore gathering line in a rural area that meets all of the following criteria: (1) A nominal diameter from 6⅝ to 8⅝ inches; (2) located in or within ¼ mile of an unusually sensitive area, as that term is defined in § 195.6; and (3) operating at a maximum pressure established under § 195.406 corresponding to a stress level greater than 20 percent of the specified minimum yield strength (SMYS) of the line pipe or, if the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure of more than 125 psig.

[12] ''Pipeline Safety—Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments,'' 86 FR 63266 (Nov. 15, 2021) (''Gas Gathering final rule'').

[13] Class locations, defined at § 192.5, are determined depending on the number of dwellings within 220 yards on either side of a pipeline and reflect the population density around the pipeline.

[14] 58 FR 51735 (Oct. 4, 1993).

[15] PHMSA explains in the RIA that, although the Environmental Assessment for this rulemaking provides illustrative quantifications of avoided greenhouse gas emissions from this final rule, PHMSA's evaluation of the greenhouse gas emissions within its cost-benefit analysis is on the basis of qualitative assessment of those avoided emissions.

pertinent natural gas and hazardous liquid pipelines to take prompt identification, isolation, and mitigation actions with respect to unintentional or uncontrolled, large-volume releases of natural gas or hazardous liquids during a pipeline rupture. The safety enhancements in this final rule, therefore, are expected to improve public safety, reduce threats to the environment (including, but not limited to, reduction of greenhouse gas emissions released during ruptures of natural gas pipelines), and promote environmental justice for minority populations, low-income populations, or other underserved and disadvantaged communities. PHMSA has, therefore, determined that these (unquantified) public safety, environmental, and equity benefits of the final rule described in this final rule and its supporting RIA and Environmental Assessment justify the costs of the final rule.

II. Background

A. Pipeline Ruptures

Although pipelines are generally considered to be an efficient and relatively safe means of transporting natural gas and hazardous liquids,[16] they can experience large-volume, uncontrolled releases that can have severe consequences. Such rupture events can be aggravated by some combination of: Missed opportunities by the operator to identify that a rupture has occurred; the failure of operating personnel to take appropriate actions once a rupture has been identified; delays in accessing and closing available pipeline segment isolation valves; and an inability quickly to close isolation valves that would have the most significant impact in mitigating the consequences of a rupture. Typically, these types of events where a significant amount of time passes between initiation and isolation of a rupture have been the most serious in terms of monetary and environmental damages and safety consequences. The Marshall, MI, and San Bruno, CA, incidents are examples of rapid failure events with large-volume releases on high-pressure, large-diameter pipelines with serious consequences exacerbated by delays in identification and isolation of the ruptures.

The intent of this final rule is to require design and equipment elements and improved operational practices for quick and efficient identification of ruptures, that in turn will improve rupture mitigation and shorten rupture isolation times for certain gas transmission, gathering, and hazardous liquid pipelines. Rupture isolation time, as it is discussed in this final rule, is the time it takes an operator to identify a rupture after a notification of potential rupture, implement response procedures, and fully close the appropriate valves to terminate the uncontrolled flow of commodity from the ruptured pipeline segment.

PHMSA and NTSB investigations of recent natural gas transmission and hazardous liquid pipeline ruptures have identified issues relating to the timeliness of rupture identification and the appropriateness and timeliness of operators' responses to identified ruptures. Typically, no single event contributes to the deficiencies in rupture identification and response. Instead, there are multiple contributing factors associated with the technology, design, equipment, procedures, or human elements that result in inadequate rupture identification and response efforts. In some rupture scenarios, certain aspects of an operator's rupture identification or response efforts appeared adequate, but other issues, such as delayed access to isolation valves, resulted in an inadequate response overall.

For example, in the Enbridge accident near Marshall, MI, the pipeline operator had installed a leak detection system (LDS) and SCADA system that notified the operator of a potential rupture within minutes of the actual event, but issues related to the operator's procedures, training, and personnel response resulted in an 18-hour lapse before the operator confirmed the rupture and initiated mitigating actions. In the PG&E incident in San Bruno, CA, the operator effectively identified through its LDS or SCADA systems that there was in fact a rupture, but then took another 95 minutes to isolate it. This delay proved catastrophic due to the time required for confirming the existence of the rupture, assembling response personnel, traveling to the valve site, and closing the valve to isolate the pipeline segment—during which time a fire resulting from the rupture burned unabated. The NTSB's report on that incident noted that PG&E lacked a detailed and comprehensive procedure for responding to large-scale emergencies such as a transmission pipeline break, and that the use of ASVs or RCVs would have reduced the amount of time taken to stop the flow of gas.

Prior to those rupture events, the NTSB noted similar issues related to rupture response in its report on an incident occurring on March 23, 1994, in Edison Township, NJ.[17] In the Edison incident, the operator took nearly 2½ hours to stop the flow of natural gas from a ruptured pipeline in a highly-populated area. The fire that followed the rupture destroyed 8 buildings, caused the evacuation of approximately 1,500 apartment residents, and resulted in more than $25 million (approximately $40 million in 2020 dollars) worth of property damage. The NTSB report quotes the operator of that pipeline in saying that it could typically notify employees to close valves within 5 to 10 minutes after identifying a rupture, and that the time it took to close a manual valve depended on the employee's travel time to the valve site: Its employees could usually arrive at a valve site within 15 to 20 minutes, but in some instances it could take more than an hour for employees to arrive at certain valve locations after being dispatched. With this in mind, the NTSB concluded that the lack of automatic or remote-operated valves on the ruptured line prevented the operator from promptly stopping the flow of gas to the failed pipeline segment, which exacerbated damage to nearby property. Subsequently, the NTSB recommended to PHMSA's predecessor, the Research and Special Programs Administration, that it expedite establishing requirements for installing automatic or remote-operated valves on high-pressure pipelines in urban and environmentally sensitive areas to provide for rapid shutdown of failed pipeline systems.

B. National Transportation Safety Board Recommendations

In its report on the PG&E gas transmission pipeline incident that occurred in San Bruno, CA, the NTSB issued safety recommendations P–11–8 through P–11–20 to PHMSA.[18] Pertaining to this rulemaking, NTSB safety recommendation P–11–10 recommended that PHMSA require operators to equip their SCADA systems with tools, including leak detection systems and appropriately spaced flow and pressure transmitters along covered transmission lines, to identify leaks (and ruptures); and NTSB safety recommendation P–11–11 recommended PHMSA require operators

[16] *See* PHMSA, Letter to Congress, Report on Shipping Crude Oil by Truck, Rail, and Pipeline at 2 (Oct. 2018), *https://www7.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/70826/report-congress-shipping-crude-oil-truck-rail-and-pipeline-32019.pdf.*

[17] NTSB, PAR–95–01, ''Pipeline Accident Report; Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire; Edison, New Jersey'' (Jan. 18, 1995), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR9501.pdf.*

[18] *See supra* note 3.

install ASVs or RCVs in HCAs and Class 3 and 4 locations, with the valve spacing based on risk analysis.

PHMSA determined that, although the NTSB directed these recommendations to a rupture on a gas transmission pipeline, certain aspects of these recommendations are also applicable to ruptures on gas gathering and hazardous liquid pipelines, including the regulated hazardous liquid gathering pipelines regulated under part 195. PHMSA took these recommendations into account when developing this final rule by requiring that RMVs and alternative equivalent technologies be capable of having their status controlled or monitored (directly, or indirectly via the upstream pressure, and the downstream pressure) remotely,[19] and by requiring the installation of RMVs, or equivalent alternative technologies, at intervals of no more than 8 miles in Class 4 locations and 15 miles in Class 3 locations.

C. Advance Notices of Proposed Rulemaking

PHMSA published two ANPRMs seeking comments regarding the revision of provisions in the Federal Pipeline Safety Regulations governing safety of hazardous liquid pipelines and natural gas pipelines.[20] PHMSA responded to pertinent comments received on the ANPRMs in Section III of the NPRM preceding this final rule. PHMSA addressed other topics raised in the hazardous liquid and gas transmission ANPRMs within other rulemakings, as appropriate.

D. 2011 Pipeline Safety Act and Related Studies

Sections 4 and 8 of the 2011 Pipeline Safety Act established statutory requirements relating directly to topics addressed in the ANPRMs discussed previously. This final rule responds to those statutory mandates. PHMSA also considered the GAO Report No. GAO–13–168, ''Better Data and Guidance Needed to Improve Pipeline Operator Incident Response'' and ORNL Report/TM–2012/411, ''Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines With Respect to Public and Environmental Safety'' which were performed in response to the 2011 Pipeline Safety Act and are discussed further below.

i. Section 4—Automatic and Remote-Controlled Shut-Off Valves

Section 4 of the 2011 Pipeline Safety Act directs the Secretary of Transportation (Secretary), if appropriate, to require by regulation the use of ASVs or RCVs, or equivalent technology, where it is economically, technically, and operationally feasible, on hazardous liquid and gas transmission pipeline facilities that are constructed or entirely replaced after the date on which the Secretary issues the final rule containing such requirements. This final rule addresses this mandate by establishing minimum standards for the installation of RMVs or alternative equivalent technology on specified newly constructed or entirely replaced, onshore pipelines that have diameters of 6 inches or greater, including gas transmission pipelines, Type A gas gathering pipelines, hazardous liquid pipelines, and certain regulated hazardous liquid gathering lines.

a. GAO Report GAO–13–168

Section 4 of the 2011 Pipeline Safety Act required the development of a study by the Comptroller General on the ability of pipeline operators to respond to a hazardous liquid or gas release from a pipeline segment located in an HCA. In this study, published in January 2013, the GAO recommended PHMSA take the following two actions:

1. Improve the reliability of incident response data to improve operators' incident response times, and use this data to evaluate whether to implement a performance-based framework for incident response times; and
2. Assist operators in determining whether to install automated valves by using PHMSA's existing information sharing mechanisms to alert all pipeline operators of inspection and enforcement guidance that provides additional information on how to interpret regulations on automated valves, and share approaches used by operators for making decisions on whether to install automated valves.

The GAO report noted that defined performance-based goals, established with reliable data and sound agency assessments, could result in improved operator response to incidents, with ASV and RCV installation and use being one of the determining factors. The GAO further noted that PHMSA's then-current regulations for incident response and installation and use of ASVs and RCVs employed broadly-stated performance standards, requiring operators to respond to incidents in a ''prompt and effective manner,''[21] and requiring operators to install ASVs, RCVs, or emergency flow restricting devices (EFRD) if an operator determines, through risk analysis, such valves are necessary to protect HCAs.[22]

More clearly defined goals can help operators identify actions that could improve their ability to respond to certain types of incidents consistently and promptly, though identical incident response actions are not appropriate for all circumstances due to variable locations, equipment needs, configurations, and operating conditions of pipeline facilities. PHMSA agrees with the GAO's conclusions that more precise performance-based standards, in conjunction with carefully selected requirements, could be more effective in improving incident response times, particularly when ruptures are involved.

The GAO report also concluded that the primary advantage of installing and using automated valves is that operators can respond more quickly to isolate the affected pipeline segment and reduce the amount of commodity released. Although the report suggested that using automated valves can have certain disadvantages, including the potential for accidental closures, which makes it appropriate for operators to decide whether to install automated valves on a case-by-case basis, the report recognized that a faster incident response time could reduce the amount of property damage from secondary fires (after an initial pipeline rupture) by allowing fire departments to extinguish the fires sooner. For hazardous liquid pipelines, a faster incident response time could also result in lower costs for environmental remediation efforts and less commodity loss.

PHMSA applied these principles and the GAO's findings and recommendations in developing the standards in this final rule. The amendments in this final rule also include specific post-event review requirements in §§ 192.617 and 195.402. Operators must make those post-event reviews available for PHMSA to inspect, and PHMSA would be able to use those reviews to inform future rulemakings and guidance documents.

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[19] As discussed later in this document, for ASVs, an operator does not need to monitor remotely a valve's status if the operator has the capability to monitor pressures or gas flow rate on the pipeline to identify and locate a rupture. Pipeline segments that use an alternative equivalent technology must have the capability to monitor pressures or gas flow rates on the pipeline to identify and locate a rupture.

[20] 75 FR 63774 (Oct. 18, 2010) (pertaining to hazardous liquid pipelines within docket PHMSA–2010–0229), and 76 FR 53086 (Aug. 25, 2011 (pertaining to natural gas pipelines within docket PHMSA–2011–0023).

[21] For natural gas and hazardous liquid pipelines, §§ 192.615(a)(3) and 195.402(e)(2), respectively.

[22] Requirements for ASV and RCV installation on gas transmission pipelines are at § 192.935(c), and requirements for EFRD installation for hazardous liquid pipelines are at § 195.452(i)(4).

b. Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves and Hazardous Liquids and Natural Gas Pipelines With Respect to Public and Environmental Safety

In March 2012, PHMSA commissioned a study to assess the effectiveness of timely operation of automatic and remote-controlled shut-off valves recommended by the NTSB in its report on the PG&E incident and mandated by section 4 of the 2011 Pipeline Safety Act for mitigating the public safety and environmental consequences of natural gas and hazardous liquid pipeline releases. That study, whose conclusions were memorialized in the above-captioned report, also evaluated the economic, technical and operational feasibility and potential benefits of installing ASVs and RCVs in newly constructed and entirely replaced pipelines. The study concluded that:

1. In general, installing ASVs and RCVs on newly constructed and entirely replaced natural gas transmission and hazardous liquid pipelines is technically feasible, provided sufficient space is available for the valve body, actuators, power source, sensors and related electronic equipment, and personnel required to install and maintain the valve; and is operationally feasible, provided the communication links between the RCV site and the control room are continuous and reliable.

2. There is evidence that it is economically feasible to install ASVs and RCVs on newly constructed and entirely replaced natural gas transmission and hazardous liquid pipelines, and the benefits would exceed the costs for the release scenarios (guillotine-type breaks on gas transmission pipelines with diameters of 12 and 42 inches in HCAs of all class locations, as well as on hazardous liquid pipelines with diameters of 8 and 30 inches in HCAs) considered in the study. However, the study noted that it is necessary to consider site-specific variables in determining whether installing ASVs or RCVs on newly constructed or entirely replaced pipelines is economically feasible for a particular situation and pipeline.

3. Installing ASVs and RCVs on newly constructed and entirely replaced natural gas and hazardous liquid pipelines can be an effective strategy for mitigating potential fire consequences resulting from a release and subsequent ignition. Adding automatic closure capability to valves on newly constructed or entirely replaced hazardous liquid pipelines can also be an effective strategy for mitigating potential socioeconomic and environmental damage resulting from a release that does not ignite.

4. For hazardous liquid pipelines, installing ASVs and RCVs can be an effective strategy for mitigating potential fire damage resulting from a pipe opening-type breaks [23] and subsequent ignition, provided the leak is detected and the appropriate ASVs and RCVs close completely so that the damaged pipeline segment is isolated within 15 minutes after the break.

PHMSA used the conclusions of that report in developing this rulemaking and as a basis for implementing standards for valve installation per section 4 of the 2011 Pipeline Safety Act.

ii. Section 8—Leak Detection

Section 8 of the 2011 Pipeline Safety Act required the Secretary to submit to Congress a report on LDSs used by operators of hazardous liquid pipeline facilities, including transportation-related flow lines, and to establish technically, operationally, and economically feasible standards for the capability of LDSs to detect leaks.

PHMSA responded to the 2011 Pipeline Safety Act's section 8 mandate by commissioning a leak detection study.[24] The study examined LDSs used by operators of hazardous liquid and natural gas transmission pipelines and included an analysis of the technical limitations of current LDSs, the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies. It also reviewed the practicality of establishing technically, operationally, and economically feasible standards for LDS capabilities. The study addressed five tasks defined by PHMSA:

1. Assess past incidents to determine if additional LDSs would have helped to reduce the consequences of the incident;

2. Review installed and currently available LDS technologies, along with their benefits, drawbacks, and ability to be retrofitted on existing pipelines;

3. Study current LDS operational practices used by the pipeline industry;

4. Perform a cost-benefit analysis of deploying LDSs on existing and new pipelines; and

5. Study existing LDS industry standards and international regulations to determine what gaps exist and if additional standards are needed to cover LDSs over a larger range of pipeline categories.

The authors of the study were tasked only to report data and technical and cost aspects of LDSs. Although the study did not provide any specific conclusions or recommendations related to leak detection system standards, the study acknowledged that pressure/flow monitoring (leak detection techniques) will consistently and reliably catch large volume, uncontrolled release events such as ruptures. Consistent with the study findings, PHMSA has established regulations requiring RMVs and alternative equivalent technologies to be outfitted with equipment or other means to monitor valve status, commodity pressures, and flow rates.

The study also noted that operator procedures may have allowed ignoring alarms, restarting pumps, or opening valves during large releases. PHMSA addresses this concern in this rulemaking by requiring operators to confirm that a rupture is occurring following any one of the criteria specified in a new regulatory definition for the ''notification of [a] potential rupture.'' The final rule also provides for post-incident reviews that can help operators determine how best to implement lessons learned system-wide and assist PHMSA in providing industry-wide guidance regarding overarching performance issues.

E. 2020 Valve Rule NPRM

On February 6, 2020, PHMSA published the NPRM seeking public comments on the revision of the Federal Pipeline Safety Regulations applicable to the safety of certain gas transmission, gas gathering, and hazardous liquid pipelines. Specifically, the proposed language created a RMV installation requirement for onshore, newly constructed and entirely replaced gas and hazardous liquid pipelines, including gathering pipelines, with diameters of 6 inches or greater. Additionally, PHMSA proposed to shorten pipeline segment isolation times in response to rupture events. PHMSA proposed a definition for ''rupture'' and outlined standards related to rupture identification and pipeline segment isolation, including establishing a 40-minute maximum RMV closure time and a 10-minute rupture identification threshold.

In the NPRM, PHMSA also proposed requirements for RMV maintenance and inspection, spacing, risk analysis, post-incident investigation and review, and local 9–1–1 notification to help operators achieve better rupture

[23] A break in the pipeline that involves the opening of the pipe in either the circumferential or longitudinal direction.

[24] *See supra* note 9.

response and mitigation. When developing the proposals in the NPRM, PHMSA considered the relevant comments it received on the ANPRMs, as well as the related NTSB recommendations, congressional mandates, and related studies. A summary of the NPRM proposals and topics, the comments received on those specific proposals, and PHMSA's response to the comments received is set forth in Section III.

F. Subsequent Legislative Deadlines; Recent Executive Orders and Actions

Congress has revisited the rulemaking mandate in the 2011 Pipeline Safety Act in subsequent legislation. Specifically, Congress directed PHMSA to issue a final rule no later than December 20, 2020 (*see* 49 U.S.C. 60102 note). In addition, in the joint explanatory statement accompanying the Consolidated Appropriations Act for FY 2021 (Pub. L. 116–120; December 27, 2020), the conferees expressed ''disappointment'' that PHMSA had not met the December 20 deadline, and specified that PHMSA should issue a final rule within 180 days of enactment (*i.e.,* by June 25, 2021).[25]

The President has also issued a series of Executive Orders emphasizing the importance of public safety, environmental protection, and GHG reduction in Federal policymaking. Executive Order 13990 (''Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis'')[26] announced the Administration's policy to, among other things, improve public health and protect the environment, reduce greenhouse gas emissions, and prioritize environmental justice. Executive Order 14008 (''Tackling the Climate Crisis at Home and Abroad'')[27] stated the Administration's policy that climate considerations will be an essential element of United States foreign policy and national security. The order also stated the Administration's policy to organize and deploy the full capacity of Federal agencies to combat the climate crisis, using a Government-wide approach. The President also announced a new target for reductions in national GHG emissions (a 50–52 percent reduction from 2005 levels in economy-wide net greenhouse gas pollution in 2030) to combat climate change, highlighting the importance of reducing emissions of greenhouse gases other than carbon dioxide, including methane, to deliver fast climate benefits.[28] Lastly, the Administration touted the GHG emissions reduction benefits of this rulemaking within the U.S. Methane Emissions Reduction Action Plan.[29]

III. NPRM Comments, Pipeline Advisory Committee Recommendations, and PHMSA Responses

The comment period for the NPRM ended on April 6, 2020. PHMSA received approximately 30 submissions to the docket commenting on the NPRM, including comments from major industry trade associations and others following advisory committee meetings as discussed below. PHMSA also accepted stakeholders' requests to discuss this rulemaking in meetings memorialized in the rulemaking docket. Consistent with § 190.323, PHMSA considered all of these comments given their relevance to the rulemaking and the absence of additional expense or delay resulting from considering any late-filed comments.

Some of the comments PHMSA received in response to the NPRM were beyond the scope of the proposed regulations. In this final rule, PHMSA does not address the comments on pipeline safety issues that were beyond the scope of the NPRM; however, that does not mean that PHMSA determined the comments lack merit or do not support additional rules or amendments. Such issues may be the subject of other existing rulemaking proceedings or may be addressed in future rulemaking proceedings.

The Technical Pipeline Safety Standards Committee (commonly known as the Gas Pipeline Advisory Committee, or the GPAC) and the Liquid Pipeline Advisory Committee (LPAC) are statutorily mandated (5 U.S.C. App. 1–16; 49 U.S.C. 60115) advisory committees tasked with advising and commenting on PHMSA's proposed safety standards, risk assessments, and safety policies for natural gas and hazardous liquid pipelines, respectively, prior to their final adoption. Each Committee consists of 15 members, with membership equally divided among Federal and State agencies, regulated industry, and the public. The committees consider the ''technical feasibility, reasonableness, cost-effectiveness, and practicability'' of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

On July 22 and 23, 2020, the GPAC and the LPAC (collectively, the ''Committees'') met virtually to discuss this rulemaking. During the meetings, the Committees considered the specific regulatory proposals in the NPRM and discussed various comments submitted in the rulemaking docket on those proposals, including alternative regulatory language, from the pipeline industry, public interest groups, and government entities. Interested members of the public and other stakeholders were permitted to comment on the NPRM's proposals during the open portion of each meeting prior to the closed Committee discussions and voting. At the end of their closed discussions of each of the principal elements of the rulemaking, the Committees voted on whether to recommend PHMSA's adoption of the language proposed in the NPRM, or a variation thereon, as technically feasible, reasonable, cost-effective, and practicable.

This section discusses the substantive comments on the NPRM that were submitted to the docket, the GPAC and LPAC recommendations, as well as any comments received from stakeholders in writing or during meetings with PHMSA personnel before issuance of this final rule.[30] They are organized by topic and include PHMSA's response to, and resolution of, those comments.

A. General Comments, Scope, Applicability, and Cost-Benefit Issues

1. Summary of Proposal

In the NPRM, PHMSA proposed to make changes to parts 192 and 195 that applied to many regulated gas transmission, gas gathering, and hazardous liquid pipelines (including regulated rural hazardous liquid gathering pipelines).

[25] 166 Cong. Rec. H8823 (daily ed. Dec. 21, 2020) (joint explanatory statement on Consolidated Appropriations Act of FY 2021).

[26] 86 FR 7037 (Jan. 20, 2021).

[27] 86 FR 7619 (Feb. 1, 2021).

[28] *See, e.g.,* White House, ''Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies'' (Apr. 21, 2021), *https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.*

[29] White House, ''U.S. Methane Emissions Reduction Action Plan'' at 7 (Nov. 2021), *https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf.*

[30] Those written comments, and summaries for the meetings, may be found in the rulemaking docket. PHMSA notes those comments and meeting summaries largely recapitulate positions submitted in written comments on the NPRM or during the GPAC/LPAC meetings.

2. Comments Received

(i) General Support and Criticism

Commenters largely supported the content and intent of the NPRM while also submitting more specific comments on individual topics and specific requests for revision, which are summarized in subsequent sections. Industry organizations were supportive of PHMSA's intent to enhance pipeline safety by improving rupture mitigation and shorten rupture isolation times for certain natural gas and hazardous liquid pipelines. The American Fuel and Petrochemical Manufacturers (AFPM) indicated that their members rely on an uninterrupted, affordable supply of crude oil and natural gas as feedstocks to maintain their competitiveness and economic activity, and that therefore, it is important to prevent pipeline safety incidents that can disrupt supply.

The Kentucky Oil and Gas Association (KOGA) supported, in particular, the regulatory certainty provided by the rule, citing the importance of a clear framework to inform future business decisions. Additionally, the Clean Air Council and the National Association of Pipeline Safety Representatives (NAPSR) indicated support for the NPRM, the clarity it provides, and PHMSA's attention to human health and safety as well as the environment in regulating the transportation of gas and hazardous materials via pipeline across the United States.

A broad, general criticism was that the same language, criteria, and requirements are unnecessarily restated in numerous sections of the NPRM, and that the NPRM could be improved by consolidating or removing duplicative language. Other criticisms included the scope of the rule and its applicability to gathering lines, as discussed in more detail in this section.

(ii) Scope: General

The NTSB stated that, although Safety Recommendation P–11–10 specifically called for PHMSA to require leak detection equipment on gas transmission and gas distribution pipelines, that recommendation is not included in the proposed rule. The NTSB noted that the criteria proposed for ruptures in the proposed rule do not specifically provide for leak detection, and the proposed requirements for installing RMVs exclude gas distribution systems, which are a particular concern of Safety Recommendation P–11–10.

Other commenters echoed these concerns and stated that the rule should include leak- and rupture-detection requirements. The Clean Air Council stated that, because significant time is often lost during a pipeline incident in determining whether a rupture has occurred, the final rule should require operators install devices to detect ruptures. The Clean Air Council also noted that installing extra RMVs might be fruitless if an operator cannot detect the initial rupture, and went on to say that, in many rupture events, residents in the vicinity of the incident are those who discover a pipeline has ruptured, not the pipeline operators. Additionally, they noted that, in remote locations, the time between the rupture event occurring and when it is discovered is often so long that large amounts of product are lost, and the damage to the surrounding area is extreme.

The Pipeline Safety Trust (PST) stated that it has been nearly 10 years since the NTSB recommended leak detection systems, via recommendation P–11–10, that meet regulatory performance standards on all transmission and distribution pipelines, and that PHMSA must do more to further the development and use of leak detection systems beyond participating in industry standards development. The PST and the Clean Air Council also asked that PHMSA consider extending the NPRM's proposed RMV requirements to existing pipelines consistent with the NTSB's recommendations.

(iii) Scope: Distribution and Gathering Pipelines

Regarding the scope related to gas distribution pipelines, INGAA et al.[31] recommended that PHMSA limit any new gas distribution system requirements, if they were intended in the proposal, to the 9–1–1 notification requirements and the incorporation of post-incident lessons learned.

Several commenters requested clarification regarding the provisions and their applicability to gathering pipelines, with the American Petroleum Institute and Association of Oil Pipe Lines (API/AOPL) and GPA Midstream Association (GPA Midstream), for example, recommending that PHMSA provide an exception for gathering pipelines from the RMV installation requirements. These entities stated that section 4 of the 2011 Pipeline Safety Act is limited to transmission pipelines, and also that requiring gathering pipeline operators to install RMVs is not economically, technically, or operationally feasible.

KOGA and NAPSR noted that PHMSA initially stated that the NPRM would be applicable to transmission pipelines, however, both commenters noted that many of the provisions appeared to apply to gathering pipelines. NAPSR stated that, per § 192.9, Type A and B gathering pipelines must follow transmission regulations, and they requested that PHMSA clarify whether operators of gathering pipelines would have to install new valves as required by the NPRM for class location changes.

Sander Resources stated that it was unclear whether PHMSA wanted to make the proposed regulations applicable to gathering pipelines or whether gathering pipelines were inadvertently included. Therefore, they noted that PHMSA must consider whether it would be appropriate to include provisions applicable to gathering pipelines in the final rule. Similarly, the Texas Pipeline Association (TPA) stated that the regulations should not be expanded beyond the scope of the congressional mandate, which applied to transmission pipeline facilities.

(iv) Cost-Benefit

Industry organizations stated that the NPRM dramatically understated the potential costs of the proposed valve installation and rupture detection standards, noting that PHMSA's Preliminary Regulatory Impact Assessment (PRIA) estimated the annual cost of implementing the proposed rule would be approximately $3.1 million. These organizations, however, said that an estimate prepared several decades ago showed that the cost of complying with similar valve installation standards would exceed $600 million. They stated the PRIA offered no explanation for the significant discrepancy between these two cost estimates and failed to account for the true costs for the changes required, noting that PHMSA may not propose a standard for adoption without making a "reasoned determination that the benefits of the intended standard justify its costs."

These commenters further stated that the alleged underreporting of incremental annual regulatory burdens in the PRIA is particularly impactful given the extraordinary economic conditions currently confronting the oil and gas industry due to the Covid–19 global pandemic. Furthermore, GPA Midstream and Sander Resources stated that the industry expects to add more than 35,000 miles of pipeline during 2020; therefore, they suggested that it may be unrealistic for PHMSA to

[31] The American Gas Association, American Petroleum Institute, American Public Gas Association, and Interstate Natural Gas Association of America (INGAA) jointly submitted comments to this rulemaking. Throughout this final rule, their joint comment is referred to as "INGAA et al."

estimate the total annualized cost amounts at $3.1 million. This would amount to just $88 per mile on an annualized basis. Further, these commenters noted that PHMSA's estimate did not cover repair or replacement projects that are ongoing.

TC Energy Corporation commented that the cost estimates for adding actuators, controls, and telemetry to gas transmission pipelines would have added $250,000 to $375,000 per valve for a total of $4 to 6 million in additional annual costs. Based on their review of their class location projects completed in previous years, TC Energy estimated that the proposed language regarding class location replacements would add another $5 million in costs annually.

An individual suggested that the cost-benefit analysis should consider the loss of power when gas transmission or gas distribution service is interrupted. They stated reductions in serious injuries and loss of life are the most significant economic consideration, but there are additional economic factors that PHMSA should consider. Among those economic costs mentioned were cost to end users associated with interruption of natural gas supply, as well as the additional delay and costs associated with recovery efforts (*e.g.,* re-lighting pilot lights) following a service interruption.

The Clean Air Council commented that the economic feasibility of the proposed rule should not be a factor in implementing the regulations. They stated that the installation of the proposed rupture-detection and automatic-valve technology should be included in pipeline construction and repair costs and should not be considered ''extra'' infrastructure that would carry an incremental cost. They stated that, while in some cases, the necessary electricity and connectivity requirements may make RCVs and ASVs infeasible in very remote locations, in all other cases, this equipment should be considered mandatory as part of the cost of constructing or repairing a pipeline. They argued that the potential loss of life and economic costs from ruptures is enough to justify this change, and that the implementation cost is not even 1 percent of the amount of the damages the public and industry pays annually for pipeline incidents.

3. PHMSA Response

PHMSA considered all the comments regarding the NPRM's readability and redundant language while drafting this final rule and believes that this final rule more clearly states the regulations and their intended effect.

(i) Scope

General. In response to the comments from the PST and the Clean Air Council that suggested PHMSA consider extending the NPRM's proposed RMV requirements to existing pipelines consistent with the NTSB's recommendations, PHMSA first notes that such a change is beyond the scope of the NPRM. As a result, such an expansion may merit additional process (*e.g.,* a supplemental notice and solicitation of additional comments), imposing a substantial delay to a rule that is already ten years in the making. Further, application of the rule's RMV and alternative equivalent technology installation requirements to existing pipeline infrastructure would entail installation activity (*e.g.,* blowdowns of existing pipelines prior to replacement, and work in pipeline rights-of-way) that could involve significant GHG emissions and other potential environmental harms.[32]

PHMSA notes that this does not mean that operators of existing pipelines do not have to address the risks of leaks or rupture events. All operators are required under the integrity management (IM) regulations at §§ 192.935 and 195.452 to conduct risk analyses to identify measures (including installing ASVs, RCVs, or EFRDs) as appropriate to enhance safety on pipeline segments that are in or which could affect HCAs. Further, this final rule requires operators of all gas and hazardous liquid pipelines subject to the emergency planning requirements at §§ 192.615 and 195.402, respectively, to update their emergency response plans to provide for immediate and direct notification of appropriate public safety answering points (9–1–1 emergency call centers) following the notification of a potential rupture. Similarly, the final rule requires all gas and hazardous liquid pipelines subject to failure investigation requirements at §§ 192.617 and 195.402, respectively, to conduct post-rupture investigations and reviews, and to incorporate lessons learned from such investigations and reviews into their training regimes and procedures.

Regarding the provisions in this rulemaking related to leak detection, PHMSA is requiring pressure monitoring upstream and downstream of RMVs and alternative equivalent technology installed pursuant to this final rule. In doing so, PHMSA believes operators will be able to better detect and isolate ruptures, and operators can integrate the pressure monitoring equipment required by this rule into future, or current, leak detection systems and analyses.

PHMSA also notes that the Federal Pipeline Safety Regulations reflect PHMSA's commitment to ensuring robust leak detection on PHMSA-jurisdictional pipelines. Since 2002, operators of hazardous liquid pipelines have been required to evaluate and install leak detection systems in HCAs, including on pipeline segments that could affect an HCA.[33] PHMSA also issued new regulations in October 2019[34] requiring that all hazardous liquid pipelines, even those outside of HCAs, have an effective system for detecting leaks. Further, hazardous liquid pipeline operators are required to inspect the surface conditions of their rights-of-way every 3 weeks.[35] Similarly, gas distribution pipeline operators are required by §§ 192.722 and 192.723 to conduct periodic patrols and leak surveys of their distribution systems at intervals. Gas transmission pipeline operators are obliged by § 192.705 to conduct periodic patrols of their pipelines, and by § 192.706 to conduct leak surveys twice per year in Class 3 locations and quarterly for Class 4 locations.

PHMSA has also, in response to a mandate in section 120 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (Pub. L. 116–260; 2020 PIPES Act), initiated a rulemaking (under RIN 2137–AF51) to require operators of new and existing gas transmission, gas distribution, and (certain) regulated gas gathering lines implement leak detection and repair programs to achieve minimum performance standards reflecting the capabilities of commercially available advanced technologies. PHMSA will also continue to promote leak detection technology for pipelines through its research and development programs.

Application to distribution and gas gathering lines. In the NPRM, PHMSA intended for the RMV and alternative equivalent technology installation requirements to apply to new and

[32] PHMSA notes that the concerns discussed in this paragraph militate against, at the final rule stage, extending the rulemaking's scope to offshore gas and hazardous liquid pipelines. PHMSA is, however, evaluating extension in the future of the regulatory amendments in this final rule to pipeline facilities (*e.g.,* offshore pipelines, existing pipelines, additional gathering lines, and smaller-diameter pipelines) that were not within the scope of this rulemaking described in the NPRM.

[33] Design regulations for computational pipeline monitoring (CPM) leak detection systems are at § 195.134, and the operational requirements for CPM leak detection are at § 195.444. The requirement for operators of pipelines in HCAs and those that could affect HCAs to have an LDS are at § 195.452(i)(3).

[34] 84 FR 52260 (Oct. 1, 2019).

[35] *See* § 195.412.

entirely replaced regulated gathering pipelines, both for gas and hazardous liquid operators. Section 192.9 states that operators of Type A gas gathering pipelines must comply with the requirements of part 192 applicable to gas transmission pipelines, and new and replaced Type B gas gathering pipelines must follow part 192 design, construction, installation, initial inspection, and initial testing requirements applicable to gas transmission pipelines. Nothing in the NPRM stated or suggested that the regulatory amendments proposed therein would not apply to new and entirely replaced gas gathering lines as provided by the plain meaning of § 192.9. However, in this final rule, PHMSA has decided to narrow the application of the valve installation requirements proposed in the NPRM to Type A gas gathering pipelines only; Type B gas gathering pipelines are explicitly exempted from those requirements.

PHMSA adopts this limitation on the scope of the RMV and alternative equivalent technology installation requirements because of the distinguishable risk profiles associated with ruptures on Type A and Type B gas gathering pipelines. Type A gas gathering pipelines, per § 192.8, operate at higher pressures (correlating to hoop stress of 20 percent or more of specified minimum yield strength (SMYS), or pressures greater than 125 psig) and in areas of higher population density (specifically Class 2, Class 3, or Class 4 locations). As a result, ruptures on these pipelines will generally present a higher risk of public safety consequences, similar to gas transmission pipelines, warranting the additional protection that RMVs or alternative equivalent technology would provide. However, as explained in Section II. E of this final rule, PHMSA provides an exception from the valve installation requirements if an operator can demonstrate that a rupture on a new or entirely replaced Type A gas gathering pipelines in Class 2 locations would yield a PIR of 150 feet or less.

Type B gas gathering pipelines, on the other hand, as defined at § 192.8, operate at lower pressures (involving hoop stress of less than 20 percent of SMYS). Ruptures on gas gathering pipelines operating within that same pressure range are likely to have a PIR comparable to the Type A gas gathering pipelines that PHMSA exempts from its RMV and alternative equivalent technology installation requirements. The final rule therefore exempts Type B gas gathering pipelines from those same requirements. Going forward, however, PHMSA will gather and consider additional data to inform application of these requirements to additional types of gas gathering pipelines.

PHMSA has, in this final rule, further clarified that the Type C gas gathering lines established in the Gas Gathering final rule are, like Type B gas gathering lines, not subject to the RMV and alternative equivalent technology installation requirements. As explained above, the Type C gas gathering designation is new, created after publication of the NPRM and the LPAC and GPAC meetings on this rulemaking. PHMSA, therefore, declines to extend the valve installation requirements to that newly defined type of gas gathering lines in this final rule; PHMSA may, however, consider doing so in a subsequent rulemaking.

Section § 195.1 similarly provides that part 195 applies to onshore hazardous liquid gathering pipelines that are: (1) Located in a non-rural area, (2) a regulated rural gathering line as that term is defined in § 195.11, or (3) located within an inlet of the Gulf of Mexico as provided in § 195.413. Further, operators of regulated rural gathering lines have to follow specific safety provisions set out in § 195.11, one of which is that steel regulated rural gathering lines must be designed, installed, constructed, initially inspected, and initially tested in compliance with part 195. Therefore, and similarly to Type A gas gathering pipelines, regulations proposed for design and construction standards for hazardous liquid pipelines will apply to regulated rural hazardous liquid gathering pipelines absent a specific statement that the regulations do not apply to regulated rural hazardous liquid gathering pipelines.

Accordingly, in this final rule, operators of regulated hazardous liquid gathering lines must comply with the provisions of this rulemaking pertaining to hazardous liquid pipelines. Based on comments received on the NPRM and discussions at the LPAC meeting, however, PHMSA is requiring that operators of only certain regulated rural gathering lines—namely, lines that cross bodies of water greater than 100 feet wide, from high water mark to high water mark—install RMVs or alternative equivalent technologies in accordance with § 195.260(e). PHMSA has required extra valves near such water crossings for several decades under § 195.260, and similarly applies the requirements of this final rule to those lines.

As for low-stress, rural hazardous liquid pipelines, as those are defined at § 195.12, PHMSA acknowledges that a hazardous liquid pipeline operating below 20 percent of SMYS is less likely to rupture than the same pipeline operating at higher pressures. However, a hazardous liquid pipeline can leak, without rupturing, and cause significant environmental damage; further, PHMSA accident report data yields that even low-stress hazardous liquid pipelines have failed. Accordingly, although the LPAC recommended that PHMSA consider an exception for low-stress, rural hazardous liquid pipelines in the final rule, PHMSA is instead requiring that all newly constructed and entirely replaced low-stress, rural hazardous liquid pipelines with diameter of six inches or greater, including low-stress hazardous liquid pipelines in rural areas, install RMVs pursuant to this rulemaking.

PHMSA is also clarifying in this final rule that the requirements pertaining to RMVs or alternative equivalent technologies as outlined in the NPRM do not apply to gas distribution pipelines. The only requirements in this rule intended to apply to gas distribution pipelines are the requirements at § 192.615 for contacting 9–1–1 call centers and at § 192.617 pertaining to post-incident analysis and implementation of lessons learned. Although PHMSA acknowledges that there could be safety and environmental benefits from extending elements of this final rule to gas distribution pipelines, PHMSA declines to do so in this final rule as such an extension is beyond the scope of the NPRM and would require additional notice and public comment, and thus further delay issuance of this final rule. PHMSA will conduct further study and analysis evaluating which rupture response and mitigation measures (including, but not limited, those adopted in this final rule) are most appropriate for gas distribution pipelines.

(iii) Cost-Benefit

PHMSA analyzed the comments it received on the PRIA and cost-benefit issues and took them into account when drafting this final rule. PHMSA addresses those comments within the RIA in the rulemaking docket.

B. Rupture Definition

1. Summary of Proposal

In the NPRM, PHMSA proposed to introduce a new definition of ''rupture'' for gas pipelines at § 192.3 meaning any of the following events that involve an uncontrolled release of a large volume of gas: (1) A release of gas observed or reported to the operator by its field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities, and that may be representative of an unintentional and uncontrolled release event defined in paragraphs (2) or (3) of this definition; (2) An unanticipated or unplanned 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 pressure loss the need for a higher pressure-change threshold due to pipeline flow dynamics that cause fluctuations in gas demand that are typically higher than a pressure loss of 10 percent in a time interval of 15 minutes or less; or (3) An unexplained flow rate change, pressure change, instrumentation indication, or equipment function that may be representative of an event defined in paragraph (2) of this definition.

Similarly, for hazardous liquid pipelines, PHMSA proposed to introduce at § 195.2 a definition of ''rupture'' for hazardous liquid pipelines as any of the following events that involve an uncontrolled release of a large volume of hazardous liquid or carbon dioxide: (1) A release of hazardous liquid or carbon dioxide observed and reported to the operator by its field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities, and that may be representative of an unintentional and uncontrolled release event defined in paragraphs (2) or (3) of this definition; (2) An 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 than a flow rate change or pressure loss of 10 percent in a time interval of 15 minutes or less; or (3) An unexplained flow rate change, pressure change, instrumentation indication or equipment function that may be representative of an event defined in paragraph (2) of this definition.

For both definitions, PHMSA added a note stating that ''rupture identification'' was to occur when a rupture, as defined above, was first observed by, or reported to, pipeline operating personnel or a controller.

2. Comments Received

For both gas and hazardous liquid pipelines, commenters stated that the proposed definitions are unclear in many respects and that the proposed definition of rupture emphasized the sources of information an operator might use to identify a rupture, like notifications to an operator, as opposed to establishing workable criteria for determining what qualifies as a rupture.

Some commenters suggested that the release criteria PHMSA used to define a rupture were impractical and do not account for differences in pipeline system operation and monitoring capabilities. Some commenters further suggested that PHMSA proposed technically infeasible detection sensitivities.

Individual operators and trade associations provided alternative definitions for ''rupture'' and ''rupture identification'' or provided editorial changes to the definitions. Other commenters, such as the NTSB, noted that elements of the definition, including the terms ''large-volume'' and ''uncontrolled release,'' could be interpreted in several ways and could benefit from clarification.

Northern Natural Gas Company stated that the proposed definition of a rupture is too restrictive, noting that their pipeline system consists of pipelines with a series of branch or lateral lines which serve power plant or industrial customers that may change operating status several times per day with subsequent start-ups and shutdowns. They added that many of these start-ups and shutdowns would meet the proposed threshold defining a rupture, and for them to develop and maintain documentation in advance for all of these scenarios would be burdensome, extensive, time consuming, expensive, and would not result in improved pipeline safety. Therefore, they recommended that the language defining a rupture be changed to an unanticipated or unplanned flow rate change or pressure loss of 25 percent occurring within 30 minutes, or that the operator should be allowed to establish specific rupture criteria for each pipeline and maintain technical justification.

TPA stated that there should be some recognition of the difficulty of determining a 30 percent pressure drop on certain transmission pipelines, such as where a natural gas-fueled electric generation plant is located on a segment. On pipeline segments such as these, they stated, significant swings in pressure are not uncommon as the generation plant starts up, and these swings in pressure can occur with little notice.

Emerson Process Management Actuation Technologies, a manufacturer of pipeline valve operating systems and controls (including ASVs), noted that their clients typically use an actuation set point of a 20 to 30 psi pressure drop per minute with the goal of sensing a rupture but not being too sensitive to ''risk a false valve closure.'' This commenter proceeded to assert that the proposed definition could require ASV set points that are more sensitive to pressure changes than currently used within industry.

Pertaining to hazardous liquid pipelines, AFPM stated that defining a rupture as a 10 percent pressure loss is not feasible for all locations, stating that the proposed language would force operators to consider pressure drops as ruptures when such pressure drops would likely not constitute an actual rupture event. They stated further that such a measure could lead to unnecessary incident reports, even in instances when no product is released, and suggested that a rupture is better defined as a percentage of flow leaving the pipeline, typically defined as 50 percent of receipt flows or higher.

Magellan Midstream Partner, L.P. stated that the proposed rule is not clear regarding the impact of alarm persistence on determining whether a rupture is occurring and whether any momentary pressure change of 10 percent constitutes a rupture, or if the 10 percent drop would be sustained continuously over 15 minutes. Magellan also suggested that, since there are several scenarios in any given pipeline operation that could contribute to pressure drops and flow rates, a rupture should not be defined by a single variable, such as pressure or flow, but be inclusive of multiple indications that, evaluated collectively, would provide for a rupture signature.[36]

OptaSense stated that operators should rely on monitoring systems that alert them of significant events with immediacy and actionable detail to mitigate the harmful consequences of a rupture rather than relying on third-party notification. On the other hand, TPA stated that the differences in the sophistication of various operators' pressure monitoring capabilities and differing granularity of monitored pressure points, combined with the short response times in the proposed rule, support some broadening of the definition of rupture to include notifications from first responders and the public. TPA added that these notifications would need some provision for operator confirmation. Magellan Midstream Partner, L.P. suggested that the proposed rule, as

[36] Including pressure, temperature, meter flow, product characteristics, and geometry of the pipeline.

written, creates the potential for numerous false rupture alarms that could impact an operator's safety culture and desensitize an organization to the heightened awareness and urgent response that a rupture alarm should create.

Commenters also suggested PHMSA consider allowing operators to establish specific rupture notification criteria for individual pipelines based on a pipeline's unique operating environment and parameters rather than establishing one-size-fits-all criteria.

INGAA et al. stated that the proposed definition of rupture does not take into account that operators' natural gas systems and their customers' needs are unique and dynamic. INGAA et al. stated that the proposed definition arbitrarily establishes set points which require response and that PHMSA did not provide a technical basis for the 10-percent-over-15-minutes threshold in the proposed rule. INGAA et al. added that by unnecessarily triggering rupture response, PHMSA's proposed 10 percent over 15 minutes criteria may potentially compromise the reliability of service to customers. INGAA et al. stated that rather than prescribe a one-size-fits-all rupture criteria, they recommended that PHMSA direct operators to establish rupture-notification criteria for individual operating systems and to outline these criteria clearly within each operator's procedures.

TC Energy recommended that if PHMSA includes a rate of pressure drop (ROPD) in the definition of a rupture, that operators should be allowed to establish their own ROPD that would indicate a rupture. They stated that the proposed definition of a rupture does not consider that operators' natural gas systems are unique and dynamic.

Similarly, API/AOPL and GPA Midstream stated that the proposed definition of rupture relies on one-size-fits-all numerical thresholds for pressure loss and flow rates that would encompass many scenarios that are not in fact ruptures (*e.g.,* a power loss at a pump station). These entities added that PHMSA does not provide any technical justification for the proposed numeric thresholds and rigid application of the criteria that could lead to numerous false alarms and unnecessary valve closures.

Commenters requested PHMSA clarify and distinguish between the meanings of the terms ''rupture identification'' and ''notification of potential rupture'' for both gas and hazardous liquid pipelines. INGAA et al. stated that the proposed definition of rupture does not address actual ruptures but rather the notification of potential ruptures, and PHMSA should therefore re-label this definition as the ''notification of potential rupture,'' which will also provide clarity in other sections of the rule. INGAA et al. and NAPSR also stated that PHMSA should limit the definition of ''rupture'' or ''notification of potential rupture'' to gas transmission pipelines, enabling PHMSA to use the terms ''rupture'' and ''notification'' as intended throughout the rulemaking without continuously qualifying whether the requirements are applicable to only potential ruptures on gas transmission lines or to both transmission line ruptures and rupture-like events on gas distribution lines, such as excavation damages.

As noted previously, commenters, including API/AOPL and GPA Midstream, also suggested that PHMSA align the definition of rupture in this rulemaking with the definition of rupture used in PHMSA's incident report, noting the existing guidance currently used in the instructions for the part 195 accident reports state 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. These industry commenters suggested that matching the definition in the reporting instructions would promote consistency, make the regulations easier to understand, and avoid unnecessary compliance burdens. The PST added that if the definition of rupture in the proposed rule is not the same as the definition of a rupture for incident and accident reporting purposes, it will make it impossible to track the effectiveness of this rule over time and to know whether this rule is driving safety.

In response to these comments, PHMSA provided the Committees in advance of their July 22–23, 2020 meetings alternative language for consideration that would substitute the term ''notification of potential rupture'' for the definition of ''rupture'' proposed in the NPRM.

The Committees unanimously recommended that PHMSA adopt this substitute language as presented and recommended by PHMSA staff at the meeting. However, the LPAC also recommended PHMSA remove from the second criterion under the part 195 definition of ''notification of potential rupture'' any reference to a specific pressure loss-rate threshold, instead recommending that this criterion refer only to operator observation of an unanticipated or unplanned pressure loss outside of a pipeline's normal operating parameters as defined in the operator's procedures.

3. PHMSA Response

PHMSA acknowledges that having a clear definition is essential for successful implementation of the rule and considered the varying suggestions provided by commenters to clarify terms and improve understanding of, and compliance with, the final rule. Therefore, PHMSA has changed the proposed definition of ''rupture'' to a definition of ''notification of potential rupture'' as proposed to and recommended by the Committees. PHMSA intended for the definition of a ''rupture'' to provide operators with a standard to initiate rupture-mitigation measures consistently and promptly and notify emergency responders of a rupture event. PHMSA acknowledges, however, that operator response actions are more appropriately initiated on ''notification of potential rupture'' than on ''rupture'' as suggested by the NPRM. Indeed, the experience of the rupture events in San Bruno, CA, and Marshall, MI, underscore there can be a significant time lag between notification of indicia of a potential rupture and verification of a rupture. PHMSA has consequently, in this final rule, recharacterized the NPRM definition of ''rupture'' as a ''notification of potential rupture.''

PHMSA declines, however, to further modify the second criterion of the definition of ''notification of potential rupture'' to remove the NPRM's reference to a 10-percent-pressure-loss-within-15-minutes threshold as recommended by the LPAC. PHMSA's Accident Investigation Division has reviewed ruptures that have occurred the past several years that PHMSA has investigated and finds this to be an appropriate requirement. In certain cases, for example, operator pressure charts provided to PHMSA following pipeline ruptures showed pipelines operating at approximately 850 psig rapidly fall to approximately 100 psig. Another pipeline went from operating at 1,160 psig to 0 psig. In PHMSA's experience, unexpected pressure-loss events that are greater than 10 percent within 15 minutes are not routine events and are often indications a rupture has occurred. However, because PHMSA acknowledges that operators may have conditions or considerations that would cause pressure swings in excess of 10 percent within 15 minutes, PHMSA has introduced language permitting operators to document in their written procedures the need for alternative pressure-loss-rate thresholds due to the unique pipeline flow dynamics resulting from changes in demand. This final rule does not contemplate that operators must submit those written operating procedures to PHMSA in advance for notification or approval. PHMSA furthermore submits that operator concerns regarding the ''one-size-fits-all'' approach of this numerical threshold or the difficulty in predicting pressure drops given the diverse and variable demands on their systems may also be addressed by the qualifying language that any such pressure loss must be ''unanticipated or unexplained.''

PHMSA initially considered including the criteria for a ''notification of potential rupture'' within the definition sections of parts 192 and 195 (§§ 192.3 and 195.2, respectively) but found such an approach challenging. First, PHMSA found it unwieldy to include such detailed criteria in a definition section that has no enumerated paragraphs. Second, because the criteria also include requirements, PHMSA determined that the definition, including the criteria, would be more appropriately located in an operative section of the regulations. PHMSA understands the approach taken in this final rule provides improved clarity and enforceability. PHMSA used a similar approach when developing the definition of an ''unusually sensitive area'' in part 195. Therefore, in this final rule, PHMSA has established a definition for the term ''notification of potential rupture'' and has promulgated the criteria for that definition in §§ 192.635 and 195.417 for gas pipelines and hazardous liquid pipelines, respectively. PHMSA has also made editorial corrections clarifying the definitional criteria and identifying indicia—including explosions and fires in the immediate vicinity of a pipeline—discussed in the NPRM and during the Committee meetings as potential consequences (and therefore indicia) of a rupture.

PHMSA acknowledges the value in aligning any regulatory definition of the term ''rupture'' with the definitions in its parts 192 and 195 incident/accident reporting forms. However, PHMSA has decided against codifying any regulatory definition of ''rupture'' in this final rule. Should PHMSA consider introducing a regulatory definition of ''rupture'' in a future rulemaking, it will endeavor to ensure consistency between any definition in the Federal Pipeline Safety Regulations and the incident and accident reporting forms.

C. Rupture Identification Definition and Timeframe

1. Summary of Proposal

In the NPRM, PHMSA proposed new provisions (§§ 192.634(c)(1) and 195.418(c)(1)) requiring operators installing RMVs or alternative equivalent technology to isolate a ruptured pipeline segment as soon as practicable, but within 40 minutes of rupture identification—defined in the NPRM (§§ 192.3 and 195.2) as the initial report to pipeline operators, or their initial observation, of a rupture. PHMSA also solicited comments on whether to oblige operators to have procedures to identify a rupture event within 10 minutes of the initial notification to the operator. These requirements would apply to both gas and hazardous liquid pipelines.

2. Summary of Comments Received

API/AOPL, GPA Midstream, KOGA, Magellan Midstream Partner, L.P., and TC Energy Corporation stated that PHMSA should add a separate definition for the term ''rupture identification'' to specify that rupture identification occurs when a pipeline operator has sufficient information reasonably to determine that a rupture occurred. Some of these industry commenters provided alternative definitions or editorial suggestions to that end.

API/AOPL stated that the rupture identification concept is highly important in establishing the extent of an operator's obligations under the new regulations. They suggested, along with GPA Midstream, that adding a separate definition for ''rupture identification'' that is based on a reasonableness standard is preferable to the NPRM's approach of defining a ''rupture'' by reference to a list of information that may be indicative, but not conclusive, of whether there is indeed a rupture.

Northern Natural Gas Company stated that a 10-minute time limit for determining whether there is a rupture can create uncertainty in the initial actions that must be undertaken by natural gas transmission pipeline operators upon initial notification, and should be eliminated; Northern Natural Gas Company suggested that the final rule would be better focused on the time to commence shut-off of RMVs or alternative equivalent technology. Similarly, TC Energy Corporation called on PHMSA to remove the 10-minute rupture identification requirement entirely, and instead revise the regulatory text to mirror language in the NPRM preamble requiring operators to respond to a rupture as soon as practicable by closing rupture-mitigation valves, with complete valve shut-off and segment isolation within 40 minutes after rupture identification.

INGAA et al. and TC Energy Corporation stated that PHMSA should eliminate the 10-minute identification requirement because the 40-minute response standard is sufficient to ensure safety in HCAs and Class 3 and Class 4 locations. INGAA et al. further stated that the decision to shut down a pipeline should not be rushed to meet an arbitrary 10-minute threshold because it risks significant service disruptions for natural gas customers. They added that operators should be provided the necessary time to determine whether a pipeline needs to be shut down.

For hazardous liquid pipelines, API/AOPL stated that the feasibility of a 10-minute rupture identification requirement is highly dependent on the location of the pipeline. They further stated that imposing a 10-minute rupture identification requirement for pipelines in remote or difficult-to-access areas will effectively force operators of such pipelines to err on the side of being overly-conservative in responding to events as ruptures. Both API/AOPL and GPA Midstream stated that this requirement would disrupt operations, is too restrictive, and could lead to adverse consequences. API/AOPL requested that PHMSA eliminate the rupture identification timeframe or provide a longer period for rupture identification. Similar to comments made for gas transmission pipelines, GPA Midstream stated that, rather than providing a 10-minute deadline for rupture identification, PHMSA should provide operators with a 40-minute total response time for closing RMVs, manual valves, or equivalent technology following a rupture.

TPA stated that the 10-minute requirement for identifying a rupture and contacting first responders is not feasible because of the need to determine the existence of a rupture as the trigger for the determination of the start of the response time. TPA stated that existing emergency procedures and damage prevention procedures at §§ 192.615 and 195.402 already contain requirements for the timely contact of emergency responders and calls to 9–1–1 numbers, so the 10-minute notification requirement in these provisions is duplicative and unnecessary, and recommended that this requirement be deleted from the proposed rule. An individual, on the other hand, agreed that the time to identify a rupture should be no more than 10 minutes, and that emergency services must be notified right away.

At the Committee meetings on July 22 and 23, 2020, both the GPAC and the LPAC unanimously recommended that PHMSA eliminate the 10-minute rupture identification requirement because of the practical difficulties of prescribing a universal 10-minute rupture identification timeline notwithstanding the variety of pipeline locations and operational environments. In conjunction with this recommendation, the Committees also recommended that PHMSA require RMVs to be closed ''as soon as practicable'' within 30 minutes of ''operator identification of a rupture'' and that PHMSA require operators to document a method for rupture identification in their written procedures.

3. PHMSA Response

PHMSA is adopting in this final rule at §§ 192.3 and 195.2 effectively identical regulatory definitions for ''notification of potential rupture'' that reflect editorial revisions to the definitions endorsed by the GPAC and LPAC. PHMSA notes that its decision to re-cast the NPRM definition of ''rupture'' as the term ''notification of potential rupture'' reflects that timely and effective rupture mitigation demands operators undertake certain actions on notification of common indicia of a rupture. Effective and timely rupture mitigation also demands operators take action on confirming, or identifying, that a rupture is in progress.

The definition for ''notification of potential rupture'' allows an operator to consider the different pipeline operating characteristics, diverse potential rupture mechanisms, and information of varying quantity and quality in evaluating whether a rupture is, in fact, in progress, and whether additional mitigation measures are necessary. PHMSA believes this definition is flexible enough to help ensure operators reach an informed determination on whether a rupture is in progress. However, PHMSA has backstopped this flexibility by requiring within revisions to each of §§ 192.615 and 195.402 that each operator have written procedures specifying its methodology for identifying a rupture on receipt of a notification of a potential rupture. The communication of ruptures to 9–1–1 or other public safety officials was always meant to be broadly applicable to all pipeline operators—the provisions were placed in the emergency response section of the regulations applicable to all operators, and the GPAC and LPAC each recognized this intent when recommending that the proposed provisions for communicating with 9–1–1 applied to all ruptures, without exception. An operator cannot properly and promptly coordinate and share information with the appropriate public safety authorities regarding event location and planned and actual responses to an emergency if they do not have a procedure for identifying a rupture upon the notification of a potential rupture.

Consistent with the Committees' recommendations, PHMSA has decided against including within this final rule the 10-minute global rupture identification time interval proposed in the NPRM. Although PHMSA understands that a 10-minute rupture identification timeline is achievable based on currently available technology, after reviewing the written comments submitted in this proceeding, and the discussions during the Committee meetings, PHMSA has concluded that the NPRM's one-size-fits-all approach to rupture identification could be challenging in light of the diversity of pipeline operational conditions and customer requirements.

However, PHMSA remains concerned that, in the absence of a minimum rupture identification time interval, a scenario similar to those that played out during the Marshall, MI, and San Bruno, CA rupture events—in which there were extended delays in rupture identification and response despite *multiple* indicia of a potential rupture—could happen again. With that in mind, PHMSA had considered triggering this final rule's RMV operation response actions set forth in §§ 192.636 and 195.419 on *notification of potential rupture* rather than *rupture identification.* PHMSA has, however, declined to adopt such an approach in this final rule to avoid further procedural delays in realizing the safety benefits of a rulemaking that has been over a decade in the making here at PHMSA—which effort commenced over 40 years after the NTSB highlighted the public safety benefits from operators' installation of readily-available technologies such as RMVs on pipelines.[37]

As a result, PHMSA may, in future rulemakings, consider whether it is appropriate to key operator RMV operation response actions to notification of potential rupture. In the interim, PHMSA has in this final rule codified at §§ 192.615(a)(12) and 195.402(e)(4) language within the NPRM expressing its expectation that operators will, upon notification of a potential rupture, identify whether there is indeed a rupture by reference to written procedures. Operators implementing this final rule should ensure those written procedures incorporate common-sense elements including, but not limited to, waiver of any requirements for specific pipeline personnel to conduct on-scene investigation of a potential rupture if an operator receives one or more of the following: Multiple or recurring instrument indications (pressure readings, alarms, etc.) of potential ruptures; pressure drops significantly in excess of the minimum thresholds in §§ 192.635(a)(1) and 195.417(a)(1);[38] and reports of rupture indicia from on-scene, credible sources (*e.g.,* on or off-duty pipeline operator personnel, sheriff or police officers, fire department personnel, or other emergency response personnel). PHMSA understands this reading of its revisions at §§ 192.615(a)(12) and 195.402(e)(4) to be consistent with operators' obligations elsewhere in §§ 192.615(a) and 195.402(e) (as revised) to take ''necessary actions to minimize hazards of released [commodity] to life, property, or the environment.'' PHMSA further notes that any risks to the public and the environment arising from delays in rupture identification for operators installing RMVs under this final rule would be further reduced by each of (1) language in §§ 192.615 and 195.402 requiring operators to ensure that their protocols identify ruptures ''as soon as practicable'' and (2) language at §§ 192.636 and 195.419 imposing demanding timelines—''as soon as practicable,'' but not to exceed 30 minutes from rupture identification—for operation of RMVs following rupture identification.

D. RMV Installation; RMV Closure Timeframe

1. Summary of Proposal

In the NPRM, PHMSA proposed to require that all valves on newly constructed or entirely replaced onshore gas transmission and gathering

[37] *See* Homendy, ''San Bruno Victims and Their Families Deserve Long-Overdue Action'' (Sept. 9, 2020), *https://safetycompass.wordpress.com/category/infrastructure/* (last visited Nov. 8, 2021) (*referencing* NTSB, PSS–71–1, Special Study of Effects of Delay in Shutting Down Failed Pipeline Systems and Methods of Providing Rapid Shutdown (Dec. 31, 1970), *https://www.ntsb.gov/safety/safety-studies/Documents/PSS7101.pdf*).

[38] PHMSA submits that operators may be able to leverage other provisions in this final rule (§§ 192.636(d)–(e) and 195.419(d)–(e)) pertaining to upstream/downstream pressure monitoring to support timely rupture identification without the need for on-scene investigation of a potential rupture.

pipelines that have diameters greater than or equal to 6 inches be RMVs or an alternative equivalent technology. Operators seeking to use an alternative equivalent technology in lieu of an RMV would have needed to submit a notification to PHMSA demonstrating that their preferred technology would provide an equivalent level of safety to an RMV. And should an operator seek to use a manual valve as an alternative equivalent technology, the operator would also have had to demonstrate that installation of an RMV would not be economically, technically, or operationally feasible. All valves installed per this proposal would meet the new rupture-mitigation standards proposed in § 192.634 and isolate a ruptured pipeline segment within 40 minutes of rupture identification.

Similarly, for hazardous liquid pipelines, PHMSA similarly proposed to require that all valves on newly constructed and entirely replaced onshore hazardous liquid pipelines that have diameters greater than or equal to 6 inches be RMVs or alternative equivalent technology. Operators seeking to use an alternative equivalent technology in lieu of an RMV would have needed to submit a notification to PHMSA demonstrating that their preferred technology would provide an equivalent level of safety to an RMV. And should an operator seek to use a manual valve as an alternative equivalent technology, the operator would also have had to demonstrate that installation of an RMV would not be economically, technically, or operationally feasible. All valves installed under this proposal would meet the new rupture-mitigation standards proposed in § 195.418 and isolate a ruptured pipeline segment as soon as practicable, but within 40 minutes of rupture identification.

2. Comments Received

The PST stated that the proposed rule did not provide sufficient rationale regarding how PHMSA arrived at a 40-minute shutdown requirement, other than a suggestion that it is ''reasonable.'' They stated that they have seen spill response plans for hazardous liquid pipelines claiming that failures isolated within 15 minutes constitute an operator's worst-case discharge. If those are accurately identified as the worst-case discharges, the PST noted, then valves must be able to close that fast or even more quickly. They stated that PHMSA's determination of the maximum allowable shut-off period should be justified by data relating to the speed with which automatic valves can shut, and if they can shut more quickly, then the maximum allowable valve closure period should be shortened to that length of time. Similarly, the NTSB suggested that the 40-minute valve closure time period is longer than expected for remote or automatic valves. The NTSB suggested that, if PHMSA determined that shut-off valves are not capable of isolating pipeline segments in less than 40 minutes, every facility response plan calculating the worst-case discharge based on a valve closure of less than 40 minutes after rupture identification should be re-evaluated.

Conversely, Northern Natural Gas Company asserted that the requirement for closing a valve to isolate a rupture within 40 minutes does not allow adequate time for the pipeline controller to evaluate the nature of the pressure change, determine if there is an emergency, or identify the actions needed to mitigate the emergency. Therefore, Northern Natural Gas Company recommended PHMSA change the rupture identification and valve shut-off period to 60 minutes total. It stated that a 40-minute valve closure requirement could result in too-rapid decisions to shut-in pipeline segments, causing unnecessary outages, unanticipated pressure changes, and potential damage to the pipeline system. It also stated that, within the States where it operates, unplanned, sudden outages could cause major problems with prolonged loss of heat to residences, businesses, and government facilities as well as an interruption of electric power generation and industrial processes.

INGAA et al. recommended that PHMSA apply the 40-minute valve closure time only to pipelines in HCAs and Class 3 and Class 4 locations to allow more flexibility in remote areas, noting specifically that achieving valve closure within 40 minutes is typically more challenging in remote areas. They noted that operators are likely to consider the use of manual valves in remote areas because an ASV, RCV, or equivalent technology would be economically, technically, or operationally infeasible, as it can be difficult to provide power or communications to automated valves in remote areas. INGAA et al., further noted that pipelines traverse a multitude of geographies, including locations that cannot safely be reached within 40 minutes, particularly during winter months.

Similarly, AFPM and other commenters representing hazardous liquid pipeline operators also requested that PHMSA consider flexibility for response time in remote areas where manual valves are located, stating that, according to information submitted by AFPM members after a review of their respective systems, manual valve response times in certain scenarios would potentially exceed 40 or 60 minutes. AFPM stated that the increased response time is due to the location of field employees and their ability to reach remote locations, and that some valves may take up to 10 to 20 minutes to close once personnel are at the valve site. Therefore, these commenters stated that manual valves installed in accordance with the RMV installation requirements should not need to meet the proposed 40-minute valve closure standard.

GPA Midstream, like other commenters, provided specific regulatory text for streamlining the requirements related to the valve closure period. GPA Midstream also recommended that operators be allowed to seek authorization from the Associate Administrator for Pipeline Safety to use an alternative shut-off time in appropriate cases, stating that there may be circumstances where an operator cannot meet the 40-minute shut-off time.

INGAA et al. asserted that the 40-minute response time would not be practicable or appropriate to apply to existing pipelines, should PHMSA consider such a proposal in a future rulemaking. INGAA et al. claimed a 40-minute closure time is on the leading edge of what is practicable under currently-available technologies that could be applied to new and replaced pipelines. They noted that multiple PHMSA special permits contain a 60-minute valve closure time requirement, and operators have proactively taken steps to attain the 60-minute response target while the current rulemaking has been pending for almost a decade.

Further, INGAA et al. stated that, even for new and replaced pipelines, attaining the 40-minute valve closure time will push the limit of what is currently technologically and operationally possible. They noted that for almost 60 percent of PHMSA-reportable ruptures from 2010 to 2019, the response time was greater than 40 minutes, which, they claimed, would indicate any response time shorter than 40 minutes for new and replaced pipelines would be infeasible. Similarly, Magellan Midstream Partners L.P. stated that 40 minutes is not a practical travel time to manual valves that have been installed in accordance with the RMV installation requirements.

Commenters also suggested PHMSA should provide an allowance for scenarios where the operator and emergency responders agree not to shut an RMV following a rupture.

At the Committee meetings on July 22 and 23, 2020, the Committees unanimously endorsed the NPRM's RMV closure requirements as ''technically feasible, reasonable, cost effective and practicable'' provided that PHMSA reduce the RMV closure time to 30 minutes in combination with eliminating the proposed 10-minute rupture identification standard. PHMSA understands that endorsement to reflect Committee discussions in which industry representatives focused their objections to the NPRM on the difficulty of meeting the 10-minute rupture identification timeline given differences in environmental conditions and operational requirements within their systems.

Further, the GPAC recommended PHMSA review the issue of allowing certain valves to remain open during emergency situations based on the Committee discussion and public comments and ensure that the integrity of the rule was not compromised and would minimize environmental damage.

The GPAC also recommended PHMSA allow, for natural gas pipelines, manual valves installed as alternative equivalent technology in non-HCA Class 1 locations to exceed the 30-minute closure time requirement only if the operator submits within its notification to install such valves as alternative equivalent technology a specific closure time for those manual valves. For hazardous liquid pipelines, the LPAC recommended a similar limitation apply to manual valves used as alternative equivalent technology in remote, non-HCA locations.

3. PHMSA Response

As a part of developing the NPRM, PHMSA considered what would make it economically, technically, or operationally infeasible to install or use an ASV, RCV, or equivalent technology. For instance, PHMSA proposed to limit the installation of ASVs, RCVs, equivalent technologies (including, potentially manual valves) to pipelines of 6 inches and greater because, while rupture-mitigating technologies are commercially available for pipelines as small as 2 inches in diameter, PHMSA determined at the time that it is unlikely the safety and environmental benefits on those pipelines would justify the costs of installing the technology. While PHMSA applies these requirements to pipelines of 6 inches in this final rule, PHMSA may consider expansion of this application for smaller pipeline diameters in a future rulemaking. PHMSA would analyze the costs and potential safety and environmental benefits of an expansion in any such rulemaking.

PHMSA also noted in the NPRM that examples of where it might be infeasible to install ASVs or RCVs included locations that may have issues with communication signals, power sources, space for actuators, or physical security. These locations can vary and are not limited to certain types of terrain. Certain urban areas, for example, might have access to power sources but might not have adequate physical space for the necessary valve actuators. Certain rural areas, on the other hand, might have issues with maintaining continuous communication signals or might have difficult-to-access valves. Other reasons that installation of RMV may be infeasible identified in written comments and during GPAC/LPAC meetings include difficulties in obtaining required access rights or permits. The COVID–19 global health emergency has also exacerbated labor and component constraints, drawing out procurement timelines and increasing costs.

However, given that these valve installation requirements apply to new construction and replacement projects whose routes and components are planned out years in advance, PHMSA does not believe that there should be major economic, technical, or operational constraints impacting valve installation. Final Environmental Impact Statements for pipeline projects proposed after the passage of the Pipeline Safety Act of 2011 have shown that operators are committing to installing a substantial number of remotely operated and monitored valves. However, PHMSA does not want to preclude unforeseen challenges or conditions operators may face in installing valves pursuant to this rulemaking, and so developed an advance notification process at §§ 192.18 and 195.18, by which operators can (subject to PHMSA's review) make a site-specific case before installation of an alternative equivalent technology that (1) the technology would provide an equivalent level of safety to an RMV, and (2) if that proposed alternative equivalent technology is a manual valve, installation of an RMV would be economically, technically, or operationally infeasible. Similarly, PHMSA has in this final rule established procedural machinery allowing operators to request extensions of compliance timelines for installation of RMVs and alternative equivalent technology is such timelines are economically, technically, or operationally infeasible for near-term construction and replacement projects.

PHMSA also considered what would make a technology ''alternatively equivalent'' to the ASVs and RCVs that the statute specifically listed. In developing the NPRM, and given the circumstances noted above, PHMSA wanted to provide operators with flexibility to install the appropriate valve or technology based on the unique circumstances at each site while still ensuring that such valves or technologies would close as soon as practicable.[39] In the NPRM, PHMSA also noted that, in the Marshall, MI incident, the rupture-mitigating valves the operator had equipped on the line were functionally useless until the operator was able to identify the rupture. Therefore, PHMSA believed that any proposed regulation would need to pair a valve installation requirement with a standard delineating when an operator must identify a rupture and actuate those valves. PHMSA did not consider it appropriate to assign different valve closure times to different rupture-mitigating valves or technologies, because doing so would have made compliance and enforcement difficult.

PHMSA believed that, by setting a valve and technology closure standard for operators to meet, it would contribute to PHMSA's review of notifications contending that an alternative technology would provide an equivalent level of safety to an RMV. This approach allows operators to install the most appropriate valve or technology given site specifics, and it also prevents PHMSA from inadvertently restricting the development or use of promising rupture-mitigating technologies by imposing prescriptive requirements on the use of ''equivalent technology,'' which was not defined by the statute. As discussed throughout the NPRM and this final rule, PHMSA does expect operators to be able to close certain valves or technologies faster than others, and has included requirements for operators to close RMVs or alternative equivalent technologies ''as soon as practicable'' but within the required timeframe.

PHMSA maintains that the proposed 40-minute RMV closure standard is achievable with current technology, and it would be a significant improvement over the 95 minutes it took PG&E to

[39] PHMSA notes that, as contemplated by the NPRM, such alternative technologies can include manual valves if an operator makes the requisite showings of safety equivalence and technical, operational, or economic infeasibility of RMV installation. *See, e.g.,* 85 FR at 7178.

close the necessary valves during the incident at San Bruno, CA. As discussed in the NPRM, recent PHMSA-issued special permits for non-looped pipelines contemplate those lines will be equipped with isolation valves that can be closed in 30 minutes or less. PHMSA proposed a higher ceiling (40 minutes) in the NPRM because many gas and hazardous liquid systems have several incoming and outgoing product receipts and deliveries or tie-ins and, in some situations, multiple loop lines; establishing a one-size-fits-all requirement for valve closure times on all gas and hazardous liquid pipeline systems can be challenging based on the configuration of those systems. In the NPRM, PHMSA also noted that it considered valve closure times between 30 and 60 minutes based on comments on the ANPRMs and work on the ''Alternative MAOP'' rulemaking.[40]

PHMSA notes that it developed the 40-minute RMV closure standard in the NPRM accounting for the potential need to include manual valves as alternative equivalent technology due to site-specific concerns; PHMSA assumed and expects ASVs and RCVs will be closed much faster. In the NPRM, PHMSA proposed to allow operators to use manual valves as an alternative equivalent technology, with a notification to PHMSA demonstrating that installing an ASV or RCV would be economically, technically, or operationally infeasible, and that a manual valve would provide an equivalent level of safety to an RMV. The NPRM's proposal reflected PHMSA's belief it would be reasonable to apply a 40-minute valve closure standard to provide time (if needed) for operators to get personnel on-site to close any necessary manual valves.

As discussed elsewhere in this document, both the GPAC and the LPAC each unanimously voted to characterize a shortened valve closure time as ''technically feasible, reasonable, cost-effective, and practicable'' provided that the NPRM's prescriptive timeframe for rupture identification was eliminated. PHMSA acknowledges that a faster valve-closure standard would provide additional environmental and public safety benefits and has revised this final rule to require a 30-minute maximum valve-closure time, measured from rupture identification—with an emphasis that this is a ceiling whereas the actual requirement is ''as soon as is practicable.'' As noted by some of the commenters, many operators indicate ''worst case scenarios'' of 15 minutes.

[40] 73 FR 62147 (Oct. 17, 2008).

Accordingly, PHMSA is requiring any RMVs and alternative equivalent technology installed pursuant to this final rule be closed ''as soon as practicable'' but no later than 30 minutes following the identification of a rupture. In addition, as suggested in comments from PST, those operators that have indicated in their spill response plans a valve closure time of less than 30 minutes during a worst-case discharge would still have to operate such valves in the time indicated in their spill response plan (*see* § 194.105(b)(1)). If an operator chooses to install ASVs as RMVs, they must conduct flow modeling for the applicable pipeline segments and any laterals that feed the pipeline segment to ensure that the ASV will close within 30 minutes or less following rupture identification. The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions (including extreme fluctuations in weather that might affect operating pressures) that may be, or are anticipated to be, encountered during the year, not to exceed a period of 15 months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or gas receipt tie-ins. If operating conditions change in a way that could affect the ASV set pressures and the valve closure time after rupture identification, an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with § 192.745. The flow model must include a pressure drop/time chart or graph for the segment containing the ASV if a rupture event occurs and must show rupture segment isolation as soon as is practicable and within 30 minutes of rupture identification. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could assure that the 30-minute valve closure time is achievable. If an operator does not perform this flow modeling correctly, the set pressure could be too low, thus rendering a 30-minute closure time unachievable.

When conducting flow modeling for ASVs, operators should also consider what type of rupture may occur on their system, especially whether the rupture may be a pipe-body type or a seam-type failure. The flow model detection for a rupture should be based on 0.5 times the pipe diameter (or less) pipe area when sizing the pressure drop for a rupture.

Operators also have the option, in lieu of installing RMVs, to install alternative equivalent technology with an advance notification to PHMSA in accordance with §§ 192.18 and 195.18. An operator must include, for PHMSA's review, a site-specific technical and safety evaluation in its notice consisting of the following information, as well as any other information requested by PHMSA in its review of the notification: Design, construction, maintenance, and operating procedures; technology design and operating characteristics such as operation times (closure times for manual valves); service reliability and life; accessibility to operator personnel; nearby population density; and potential consequences to the environment and the public. Where the operator proposes to use manual valves as alternative equivalent technology, its notification to PHMSA must also demonstrate that installation of an RMV would be economically, technically, or operationally infeasible by reference to factors such as access to communications and power; terrain; prohibitive cost; component and labor availability; ability to secure required access rights and permits; and accessibility to operator personnel for installation and maintenance.

As discussed above, PHMSA is requiring an ''as soon as is practicable'' valve closure time (with an absolute ceiling of 30 minutes), measured from rupture identification pursuant to an operator's written procedures, in conjunction with eliminating the 10-minute rupture identification timeframe. Shortening the time it takes for an operator to close a RMV or alternative equivalent technology provides a better mitigation standard to protect the public and the environment from the consequences of a rupture. PHMSA notes that it has seen evidence of operators being able to isolate looped pipeline systems in less than 10 minutes—this rule should help ensure this timeframe is widely achievable. Operators of hazardous liquid pipelines must also consider the shut-down times they use when calculating worst-case discharges in accordance with § 194.105 and be able to close RMVs within that timeframe if it is less than 30 minutes.

For gas pipelines, some commenters suggested allowing operators to exceed the 30-minute closure standard if using manual valves as alternative equivalent technology in non-HCA, Class 1 locations, if the operator submits a notification demonstrating that installing an RMV would be economically, technically, or operationally infeasible. Given that non-HCA Class 1 locations are largely rural areas, PHMSA believes such a provision would be warranted if the operator could demonstrate they could not install a compliant valve or technology in those locations. In this final rule at § 192.636(g), PHMSA specifies that an operator seeking an exemption from the rule's RMV and alternative equivalent technology 30-minute operation requirement would, within its request submitted under § 192.18, have to provide PHMSA for its review, inter alia, with an estimated closure time of any manual valve employed as an alternative equivalent technology. PHMSA has not included procedural machinery for such an exemption from that operation requirement for manual valves used as alternative equivalent technology in non-HCA Class 2 locations in this final rule, however, because those locations would pose a greater risk to public safety: By definition, Class 2 locations have a minimum of 10 houses and up to 45 houses in the class location unit near the pipeline. The final rule incorporates at § 195.419(g) an analogous procedure for certain hazardous liquid pipelines (specifically, those that are neither in, nor could affect, an HCA) whereby an operator can request an exemption from the 30-minute operation requirement at § 195.419(b) when employing a manual valve as an alternative equivalent technology; those pipelines, too, pose a lower risk to public safety and environment from hazardous liquid pipeline segments which are located in, or could affect, an HCA.

In this final rule, PHMSA does not authorize operators, in conjunction with emergency responders, to leave RMVs or alternative equivalent technologies open for rupture mitigation or safety during emergency response, without first forwarding to PHMSA pursuant to §§ 192.18 or 195.18 such a request and developing appropriate written procedures. PHMSA believes that the need to isolate ruptures is paramount—precisely to be able to afford maximum safety for an emergency response as well as for mitigation purposes—and that RMVs and alternative equivalent technologies should be closed as soon as practicable. Any discussions occurring with emergency responders while an incident is occurring could lead to unjustified delays in isolating ruptures. If an operator has not established the need in their operating procedures for not closing valves prior to a rupture, the emergency responder(s) would probably not have the appropriate information to make such a decision promptly. Commenters at the GPAC meeting noted that there might be instances where leaving RMVs or alternative equivalent technologies open during emergencies was warranted, such as when the pipeline was the sole product source for a power plant or a hospital, or where closing a RMV or alternative equivalent technology would then have an adverse economic impact on other customers downstream. PHMSA has determined that, in situations such as these, the potential risks associated with interruption of gas supply to particular end users will generally outweigh the value of more quickly mitigating the nearly certain catastrophic consequences of a pipeline rupture. PHMSA notes that a rupture may itself result in interruption of service to critical facilities and electric generators, regardless of response actions taken by operators. Further, PHMSA notes that bi-directional product flow or the residual volume of product downstream of a ruptured pipeline segment can provide operators with time to isolate the ruptured pipeline segment while also redirecting product flow as necessary to ensure that any disruption to downstream facilities would be minimized. PHMSA also contemplates operators will appropriately plan for the aforementioned contingencies.

Based on the GPAC discussion, however, PHMSA has provided in this final rule a mechanism for an operator to forward to PHMSA such a request. Accordingly, an operator of a gas pipeline may request pursuant to § 192.18 to plan to leave an RMV or alternative equivalent technology open for more than 30 minutes following rupture identification if the operator can demonstrate to PHMSA that closing that RMV or alternative equivalent technology would be detrimental to public safety. Such a request must be coordinated in advance with appropriate local emergency responders, and the operator and applicable emergency responders must agree that it would be safe to leave the valve open. If PHMSA grants such a request to an operator, that operator would be required to have written procedures for determining when to leave a RMV or alternative equivalent technology open, including all plans for communicating with local emergency responders during a rupture event during which the RMV or alternative equivalent technology would be left open, and including measures by which the operator would minimize environmental impacts.

Regarding the comments requesting clarification on the meaning of ''other mitigative actions,'' PHMSA intended this phrase to require that operators take whatever action is appropriate to mitigate the event, in addition to closing the appropriate RMVs or alternative mitigative technologies. The specific actions PHMSA would expect an operator to take would be dependent on each unique rupture scenario and may include, but are not limited to, the closure of valves on laterals used for receipt or delivery and communication with product receipt and delivery customers.

E. RMVs

1. Summary of Proposal

In the NPRM, for gas pipelines, PHMSA proposed to require that all valves on newly constructed or entirely replaced onshore gas transmission and gathering pipelines that have diameters greater than or equal to 6 inches be ASVs, RCVs or an alternative equivalent technology. Operators seeking to use manual valves as an alternative equivalent technology would also need to demonstrate to PHMSA's satisfaction that installing an ASV or RCV was economically, technically, or operationally infeasible. PHMSA proposed to define the statutory phrase ''entirely replaced'' as being where an operator replaces 2 or more contiguous miles of pipeline with new pipe. All valves installed per this proposal would meet the new rupture-mitigation standards proposed and isolate a ruptured pipeline segment within 40 minutes of rupture identification. PHMSA also proposed that new or entirely replaced laterals contributing 5 percent of the total volume of the applicable gas line shut-off segment would also require RMVs.

For hazardous liquid pipelines, PHMSA similarly proposed to require that all valves on newly constructed and entirely replaced onshore hazardous liquid pipelines that have diameters greater than or equal to 6 inches be RCVs, ASVs, or an alternative equivalent technology. PHMSA proposed to permit operators to install manually or locally operated valves as alternative equivalent technology only when there were economic, technical, or operational feasibility issues precluding the installation of ASVs or RCVs and proposed to require operators to notify PHMSA as well. All valves installed under this proposal would meet the new rupture-mitigation standards proposed in § 195.418 and isolate a ruptured pipeline segment as soon as practicable, but within 40 minutes of rupture identification. Similar to gas transmission lines, new or entirely replaced laterals contributing 5 percent of hazardous liquid volume would also be required to install RMVs.

PHMSA also defined the term ''shut-off segment'' in the NPRM as the segment of applicable pipe between the RMVs closest to the upstream and downstream endpoints of an HCA, a Class 3 location, or a Class 4 location so that the entirety of these areas is between RMVs. Multiple HCAs, Class 3 locations, or Class 4 locations can be contained in a single shut-off segment, and all valves installed on a shut-off segment are RMVs. While PHMSA did not specifically define the term ''rupture-mitigation valve'' in the NPRM, it used that term in the NPRM to describe the ASVs, RCVs, or alternative equivalent technology installed to mitigate ruptures.

For the proposed construction and replacement requirements, PHMSA proposed an implementation timeframe of 12 months following the effective date of the rule.

2. Comments Received

(i) ''Rupture-Mitigation Valve'' and Related Definitions

API/AOPL, GPA Midstream, Magellan Midstream Partner, L.P., and TC Energy Corporation recommended that PHMSA add a definition of an RMV for clarity. These industry commenters stated that the definition of an RMV should explicitly include check valves within its scope and also specify the purpose served by these valves, which is to minimize the volume of product released following a rupture and mitigate the safety and environmental consequences of a rupture. API/AOPL and GPA Midstream added that the definition of an RMV should include automated valves, alongside ASVs and RCVs, per the GAO report. Other commenters, representing hazardous liquid pipelines operators, noted that the definition should also contain EFRDs for hazardous liquid pipelines.

PHMSA also received several comments regarding the use of additional technologies and practices. Regarding valve types, industry commenters suggested PHMSA should allow operators to use a ''locked-out'' or ''tagged-out'' manual valve as an alternative equivalent technology at crossovers, and allow operators to use a check valve as an RMV for laterals used for receipt or delivery, provided that the check valve is positioned to stop product flow into the shut-off segment. Further, industry commenters suggested that PHMSA should add language to the final rule to confirm that locally actuated ASVs would be an acceptable alternative for RMVs and that operators could select any pipeline (mainline or lateral) or station valve as an RMV as long as it complied with the RMV spacing requirements.

Commenters also had suggestions for definitions related to RMVs, including ''shut-off segment'' and ''entirely replaced.'' For ''shut-off segment,'' commenters recommended defining that term and provided assorted editorial suggestions for the definition. Similar comments were made for the term ''entirely replaced.''

Additionally, for the term ''entirely replaced,'' industry commenters noted that PHMSA discussed the definition for the term in the preamble text but did not include it in the regulatory text. They asserted that the definition that PHMSA uses for ''entirely replaced'' in the NPRM is not consistent with the plain meaning of that term, as meaning ''in every way possible; completely.'' Based on that interpretation of the definition of ''entirely replaced,'' these commenters stated that replacing a portion of a pipeline would not constitute an ''entirely replaced'' pipeline and suggested that, based on PHMSA's definition, ''entirely replaced'' could create an incentive to make poor engineering decisions based on the potential consequences of a segment being ''completely'' replaced.

The PST stated that PHMSA provided no explanation for how it arrived at the 2-mile threshold or whether recent replacement projects were tallied to see how many recent projects that distance would include or exclude. The PST asserted that choosing a shorter distance would include more replacement projects and would therefore result in more of the Nation's pipeline systems having the additional protection of ASVs or RCVs. The PST also stated that because 2 miles is a long distance, it seems an easier distance to design around to avoid application of this rule. Therefore, the PST suggested PHMSA establish the definition of ''entirely replaced'' based on a replacement length of 600 contiguous feet or a length of more than 600 feet of any contiguous 1,000 feet, which would be a distance longer than a single integrity repair might require but short enough to capture smaller replacement projects. The PST stressed the importance of this definition due to limitations on changing design and construction requirements on existing pipeline systems. Similarly, other commenters from the general public suggested that PHMSA should reduce the distance for replacement that triggers valve installation to 1 mile of contiguous pipeline.

At the Committee meetings on July 22 and 23, 2020, discussions focused on the practicability of NPRM's proposed definition of ''entirely replaced.'' Pipeline operators generally supported the 2-mile element of the definition as striking an appropriate balance between safety benefits and practical difficulties (*e.g.,* obtaining land access rights and permits) associated with installing new RMVs on replacement pipelines—provided PHMSA clarify (1) the length of the pipeline from which the 2 miles of replaced pipe would be calculated was less than each operator's entire system, and (2) the timeframe over which those pipeline replacements would be conducted so as to accommodate pipeline maintenance planning cycles. The Committees unanimously recommended that PHMSA revise the final rule so that the ''entirely replaced'' standard applies to multiple replacements that, in the aggregate, exceed 2 miles of pipeline within a 5-contiguous-mile length within a 24-month period. The Committees also unanimously recommended PHMSA allow check valves and valves on crossover piping that are locked and tagged closed in accordance with operating procedures to be used as RMVs. Committee members noted that check valves could already be considered an ASV based on their design, and that check valves have been used effectively in hazardous liquid pipeline systems.

(ii) RMV Applicability

NAPSR and other commenters requested PHMSA clarify whether the proposed requirements would be applicable to low-stress systems, noting that rupture risk is greatly reduced for systems that operate at less than 20 or 30 percent of SMYS.

Similarly, the industry associations requested that PHMSA except pipelines from the RMV installation requirements where the PIR of those pipelines is less than 150 feet. They stated that pipeline diameter alone is not an accurate indicator of the potential consequences of a rupture, as many pipelines with diameters ranging from 6 inches to 12 inches operate at pressures low enough that the impact of a rupture would be minimal. The industry associations noted that a pipeline's PIR reflects both the pipeline size and the operating pressure, and it is therefore a better measure of potential consequence than diameter alone. Further, the industry associations noted that the 2019 Gas Transmission Final Rule [41] used a PIR of less than or equal to 150 feet to establish less-stringent requirements for aspects of MAOP reconfirmation and pressure reductions.

Commenters representing hazardous liquid pipeline operators similarly requested that PHMSA exempt pipeline segments that could not affect HCAs

[41] 84 FR 52180 (Oct. 1, 2019).

from the requirement for installing RMVs to create the greatest benefit for the rule using an HCA-focused approach consistent with the risk-based philosophy of the Federal Pipeline Safety Regulations.

For both gas and hazardous liquid pipelines, industry commenters requested that PHMSA clarify whether the 5 percent volume contribution for determining the need for RMVs on laterals is based on flow rate or total volume.

At the Committee meetings on July 22 and 23, 2020, the Committees recommended that PHMSA consider exceptions from the RMV installation requirement for pipelines with SMYS of 30 percent or less and for all gas transmission and gas gathering pipelines with a PIR equal to or less than 150 feet (not for pipeline segments in Class 4 locations) considering cost-benefit issues and while maintaining the integrity of the rule. For hazardous liquid pipelines, the Committees recommended that PHMSA consider exceptions for pipelines 30 percent of SMYS or less.

Further, the GPAC recommended PHMSA consider an exception for Type A gas gathering pipelines of 12 inches or less and Type B gas gathering pipelines. Both the GPAC and the LPAC recommended that PHMSA consider the appropriateness of applying this rulemaking, or a separate rulemaking, to gathering lines.

(iii) Timeframe for RMVs To Be Operational and Implementation Period

With regard to the timeframe for making RMVs operational following operators placing pipelines into service, INGAA et al. requested that PHMSA provide operators with 14 days rather than the 7-day period proposed. They stated that several safety and operational activities must take place following the introduction of gas into a new pipeline segment, including the testing of control and communication systems, evaluating system constraints, and conducting management of change processes, which could require more than 7 days to conduct. Some commenters from industry also suggested that PHMSA change the implementation period for new construction from 12 months after the effective date to 24 months.

At the GPAC and LPAC meetings on July 22 and 23, 2020, the Committees unanimously recommended that PHMSA change the implementation period of the rule to 24 months after publication date for gas transmission and gas gathering pipelines, and consider reducing the implementation of the rule to be between 12 and 18 months for hazardous liquid pipelines. On both Committees, members representing the public (including PST) were initially reluctant to provide longer periods of time for the implementation of the rule. However, PHMSA noted during the meeting that the NPRM already provided a compliance period of 12 months after the 6-month effective date of the rule, which would have provided a compliance date of 18 months after the rule's publication. Members of the Committees representing industry (including Enbridge, National Grid, Marathon Pipeline, Colonial Pipeline, DCP Midstream, and PECO) noted that there could be significant lead time required for obtaining actuators for valves for larger-diameter pipelines, and recommended longer implementation times for the rule. As a result of this discussion, the committee ultimately recommended the 24-month implementation period. Additionally, for hazardous liquid pipelines, the LPAC also unanimously recommended PHMSA change the timeframe to activate RMVs after construction from 7 days to 14 days because of practicability concerns.

(iv) Notifications

Commenters representing hazardous liquid pipeline operators stated that PHMSA should align the various notification requirements throughout the rulemaking, including those for ''other [alternative equivalent] technology'' requests, with other part 195 notification requirements. Regarding such notifications, the PST requested that PHMSA clarify what criteria or standards are needed to justify the determination and provide for an equivalent level of safety. Commenters also requested that this notification period operate similarly to how PHMSA has created notifications for gas pipeline operators; namely, that unless an operator receives a specific objection from PHMSA or a request for more review time before the 90-day period has passed, the operator can install the technology under the assumption that PHMSA has no objection.

INGAA et al. also recommended PHMSA revise the rule so that the notification process for alternative technology such as manual valves applies to all locations, asserting that operators installing new or replaced pipelines in remote areas are likely to use this process.

At the Committee meetings on July 22 and 23, 2020, the LPAC and GPAC each unanimously recommended that PHMSA add specificity on standards for PHMSA review of ''other technology'' and manual valve notifications. The LPAC also unanimously recommended PHMSA incorporate the notification requirements of § 192.18 into the final rule and make a similar provision for hazardous liquid pipelines.

3. PHMSA Response

(i) ''Rupture-Mitigation Valve'' and Related Definitions

PHMSA notes that there was concern regarding the clarity of the terms RMV, ''shut-off segment,'' and ''entirely replaced,'' and PHMSA has revised those terms in this final rule.

For the definition of an RMV, PHMSA has made it explicit that such a valve is an ASV or an RCV. Commenters from industry requested PHMSA allow the use of certain valve technologies to satisfy the proposed RMV or alternative equivalent technology installation requirement. In this final rule, PHMSA is clarifying that a valve on crossover piping that is locked and tagged closed in accordance with operating procedures would qualify as an alternative equivalent technology. PHMSA notes that, for other technologies (such as check valves) that commenters from industry had suggested should be generally considered alternative equivalent technologies, PHMSA included a pre-installation notification procedure for alternative equivalent technologies and will consider requests to use such technologies on a case-by-case, site-specific basis. When determining the appropriateness of alternative equivalent technologies for a particular site, PHMSA will consider technical and safety information submitted by an operator including, but not limited to, design, construction, maintenance, and operating procedures; technology design and operating characteristics such as operation times (closure times for manual valves); service reliability and life; accessibility to operator personnel; nearby population density; and potential consequences to the environment and the public.

The definition of a ''shut-off segment,'' as it pertains to RMVs and alternative equivalent technologies, has been clarified in this final rule as well. These segments are only relevant when RMVs or alternative equivalent technologies are installed pursuant to this final rule for Class 3 and Class 4 locations for gas pipelines, as well as HCAs (or on pipeline segments that could affect HCAs, in the case of hazardous liquid pipelines) for gas and hazardous liquid pipelines. Shut-off segments are defined as segments of pipe located between the upstream mainline valve closest to the upstream endpoint of the new or entirely replaced Class 3, Class 4, or HCA segment, and the downstream mainline valve closest to the downstream endpoint of the new or entirely replaced Class 3, Class 4, or HCA segment. Shut-off segments can include crossover or lateral pipe depending on where that pipe connects to the specific shut-off segment. Single shut-off segments can include multiple Class 3, Class 4, or HCA pipeline segments.

Pertaining to the definition of ''entirely replaced,'' it was not PHMSA's intent to require the addition of RMVs or alternative equivalent technologies for small maintenance replacements, such as at road crossings or anomaly repairs where the pipe is replaced. PHMSA did note throughout the NPRM that it was considering ''entirely replaced'' to mean the replacement of 2 contiguous miles of pipe. Some commenters representing the public noted that pipeline operators may try to schedule replacement activities and pipeline segment lengths to circumvent the replacement mileage threshold. PHMSA determined that this concern is mitigated by the recommendations of the Committees to clarify that the RMV and alternative equivalent technology installation requirements would apply to those replacement projects where 2 or more miles of pipeline, in the aggregate, are replaced within any 5 contiguous miles within any 24-month period. PHMSA is aware that sourcing valves might take a long lead time, and that waiting to install a valve, at any location, could be deleterious to safety. Requiring the installation, or automation, where applicable, of valves where relatively larger construction projects are taking place will facilitate operators obtaining and installing the RMVs or alternative equivalent technologies required by this final rule. Accordingly, in this final rule, PHMSA has introduced specific definitions for ''entirely replaced onshore transmission pipeline segments'' and ''entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments'' meaning those gas and hazardous liquid pipeline replacement projects where 2 or more miles of pipe have been replaced within any 5 contiguous miles of pipe within any 24-month period.

(ii) RMV Applicability

Certain commenters from the industry and the industry associations requested various exemptions for the RMV and alternative equivalent technology installation requirements, including pipelines that operated at pressures below 30 percent of SMYS. Pipelines operating at pressures below 30 percent of SMYS have ruptured in the past, and low operating pressure is not a guarantee that the pipe will not rupture. However, PHMSA is aware of data that would indicate that pipelines operating at pressures lower than 20 percent of SMYS are at less risk of rupturing. A study on pipelines that ruptured while operating at low hoop stresses that was published in 2013 noted that, within the 5-year window of the study, there were seven pipeline ruptures occurring on pipelines operating at a pressure below 20 percent SMYS.[42] The authors of the study noted that, while these are not highly likely events, the likelihood is not so low where certain conditions could be present that they do not need to be considered in an operator's IM plans.

Additionally, according to PHMSA's 2019 annual report data, the population of natural gas and hazardous liquid pipelines that operate at these pressures are a small portion of the aggregate mileage of those types of pipelines across the United States.[43] Consistent with other, current regulatory requirements, PHMSA believes it is reasonable to add certain exemptions for pipeline segments operating at lower stress levels. For natural gas pipelines, PHMSA presented data during the GPAC meeting showing a correlation between pipelines operating at lower stresses and pipelines with smaller PIRs. Given that natural gas pipelines that would have a PIR of less than 150 feet would typically be either pipelines of smaller diameter that would not be subject to the requirements of this rulemaking, or larger pipelines operating at lower stresses, PHMSA believes it would be feasible to exempt such pipelines from the RMV and alternative equivalent technology installation requirements if those pipelines are in Class 1 or Class 2 locations. PHMSA did not accept the GPAC's recommendation to provide an exception, based on the pipeline's PIR, for gas transmission and gathering pipelines in Class 3 locations. Pipelines in Class 3 locations are by definition adjacent to population centers: A Class 3 location is where there are 46 or more buildings for human occupancy within the class location unit, or where there is a building or area that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. PHMSA has determined that, while it might be less likely that a gas pipeline operating at lower stresses in a Class 3 location would rupture, the potential consequences to public safety and the environment are still unacceptable.

For hazardous liquid pipelines, PHMSA notes that there are currently regulatory requirements for low-stress pipelines in rural areas. By definition (at § 195.12), these pipelines operate at stress levels equal to or less than 20 percent of SMYS. The environmental consequences of a hazardous liquid spill can linger for many years, and hazardous liquids can travel far from the initial accident site to affect other areas as well. Therefore, counter to the LPAC recommendation, PHMSA is not providing hazardous liquid pipelines that operate at lower stresses an exemption from the RMV installation and usage requirements of this rulemaking.

Some commenters (including TC Energy and the industry associations) requested PHMSA provide exemptions from RMV installation requirements for, or otherwise exclude, gas pipelines in Class 1 and Class 2 locations, and for hazardous liquid pipelines that are outside of HCAs. PHMSA notes that, for hazardous liquid pipelines, there are many locations, such as non-navigable waterway crossings, that could experience significant consequences from an accident even though they are not defined as HCAs. For gas pipelines, there have been many instances where a Class 1 location in which a pipeline has been installed has later experienced so much population growth that it has grown into a Class 3 location. Requiring operators to install RMVs and alternative equivalent technology on Class 1, Class 2, and non-HCA infrastructure is prudent and provides future generations with a baseline level of public and environmental safety that can accommodate changes in population density.

As discussed earlier in this rulemaking, PHMSA considered the recommendations the Committees made regarding the applicability of this rulemaking to gathering pipelines. For gas pipelines, PHMSA determined that the risk profile of Type A gas gathering pipelines was considerable enough not to impose a broad exception to the rule's requirements, as these pipelines tend to operate at higher pressures and are in Class 2, Class 3, or Class 4 locations,

[42] Rosenfeld & Fassett ''Study of Pipelines that Ruptured While Operating at a Hoop Stress Below 30% SMYS;'' Pipeline Pigging and Integrity Management Conference (Feb. 13–14, 2013).

[43] Seven percent of the gas transmission mileage operates at pressures below 20 percent of SMYS, which equates to approximately 21,000 miles out of 302,000 miles. For hazardous liquid pipelines, 3 percent of the total mileage operates as pressures less than 20 percent of SMYS, which equals 6,750 miles out of a total of 225,000 miles.

where there are more concentrated populations. However, based on risk profile, PHMSA did create a general exemption from the RMV and alternative equivalent technology installation requirements in this rulemaking for Type A gas gathering pipelines in Class 2 locations with a PIR of 150 feet or less. Operators of Type A gas gathering pipelines that have a PIR of 150 feet or less in a Class 2 location are not required to install RMVs or alternative equivalent technology in accordance with this rulemaking. PHMSA considered the GPAC's recommendation applicable to Type B gathering lines and determined that a broad exemption from the RMV and alternative equivalent technology requirements would be warranted, given the fact that Type B gas gathering pipelines, by definition, operate at hoop stresses less than 20 percent of SMYS. Pipelines operating at pressures that low are less likely to rupture. As noted above, PHMSA will carefully monitor data from these lines to inform future rulemaking.

For hazardous liquid pipelines, PHMSA noted earlier that regulated hazardous liquid gathering pipelines would be required to install and use RMVs and alternative equivalent technologies in accordance with this rulemaking, as hazardous liquid gathering pipelines that are in non-rural areas are required to comply with the entirety of part 195. However, PHMSA is exempting regulated rural gathering pipelines from the RMV and alternative equivalent technology requirements of this rulemaking unless they cross bodies of water greater than 100 feet wide, as ruptures on regulated rural gathering pipelines would generally involve less risk to public safety and property than non-rural gathering lines, and ruptures on regulated rural gathering lines that cross large bodies of water have the potential to cause more significant environmental damage. Regarding the comment that PHMSA should clarify whether the 5 percent volume contribution for determining the need for RMVs on laterals is based on flow rate or total volume, § 192.634(b)(3) states that the 5 percent volume contribution is based on total volume.

(iii) Timeframe for RMVs To Be Operational and Implementation Period

Regarding the timeframe for making RMVs and alternative equivalent technologies operational, PHMSA has determined that 14 days is more appropriate than the proposed 7 days given that (as noted in the comment submitted by INGAA et al.) a number of activities must take place after a pipeline has been placed into service but before an RMV is fully operational—PHMSA understands the scale and number of those activities make completion within the proposed 7-day timeline impracticable. Accordingly, PHMSA has adjusted that timeframe in this final rule. PHMSA has also provided a procedural machinery for operators to request an extension beyond 14 days if completion of necessary activities for a valve to become operational is not economically, technically, or operationally feasible (*e.g.,* due to prohibitive costs, labor or component shortages, or required permitting or access rights).

Regarding the implementation date for RMV and alternative equivalent technology installation, PHMSA notes the confusion several commenters had regarding the implementation date and the effective date of the rule. In this final rule, PHMSA is clarifying the implementation date for RMV and alternative equivalent technology installation by stating that pipelines and pipeline segments installed or entirely replaced beginning 12 months after the publication date of the final rule will be required to have RMVs or alternative equivalent technologies. PHMSA believes 12 months is a reasonable implementation period for RMV and alternative equivalent technology installation rather than the 24 months recommended by the Committees as it should provide operators with sufficient lead time to source RMV or alternative equivalent technology for planning construction and replacement projects without causing substantial implementation delay. Further, as shown in the RIA, PHMSA has found that much new pipeline construction is already obtaining and installing RMVs. If a gas or hazardous liquid pipeline operator anticipates it will not be able to meet this compliance timeframe, it may request from PHMSA, in accordance with §§ 192.18 and 195.18, respectively, additional time to comply because of economic, technical, or operational feasibility constraints (*e.g.,* labor or component availability constraints and lead times, prohibitive cost, permitting requirements, or obtaining requisite access rights) with respect to its near-term construction and replacement projects. Per the procedures at §§ 192.18 and 195.18, PHMSA has discretion to grant or deny an operator's request based on the information that the operator provides.

(iv) Notifications

Regarding the notification requirements for RMV and alternative equivalent technology installation, PHMSA acknowledges that aligning the notification process with the recently finalized § 192.18 would be beneficial. Accordingly, PHMSA has done so in this final rule for both hazardous liquid and gas pipelines. For gas pipelines, this means that PHMSA has cross-referenced the notification requirements in this final rule to § 192.18 to provide for, and build upon, the notification process that is in that section. For hazardous liquid pipelines, because there was no corresponding notification section, PHMSA has created a new § 195.18 in this final rule that functions similarly to § 192.18. For any notifications related to the RMV and alternative equivalent technology requirements of this rulemaking, § 195.18 provides a consistent process where operators submit in advance of installation the pertinent, requested information to PHMSA, and PHMSA has 90 days in which to review and respond to the request. If an operator does not receive a letter of objection or a request from PHMSA for more time or information for PHMSA to complete its review of the request within 90 days of the notification, then the operator may use the alternative technology, method, compliance timeline, or valve spacing that is being requested. Similar to the notification response process for part 192, PHMSA's objection will specify the reasons PHMSA does not approve of the proposed alternative technology, method, compliance timeline, or valve spacing, while a request from PHMSA for more time to review the request will extend the notification review period beyond 90 days. Further, to establish a verifiable record, it is PHMSA's policy to send a formal ''no objection'' letter or email, either before or after the 90-day review period, when PHMSA does not object to an operator's request in the notification.

F. Valve Spacing & Location

1. Summary of Proposal

In the NPRM, PHMSA proposed to require RMVs or alternative equivalent technologies installed on newly constructed or entirely replaced gas and hazardous liquid pipelines to be spaced at certain intervals. For gas pipelines, PHMSA proposed that the distance between RMVs or alternative equivalent technologies must not exceed 8 miles for Class 4 locations, 15 miles for Class 3 locations, and 20 miles for Class 1 and Class 2 locations in HCAs. For hazardous liquid pipelines, PHMSA proposed RMV and alternative equivalent technology spacing of 15 miles for HCAs and 7½ miles for HVL lines in populated HCAs. PHMSA also proposed valve spacing of 20 miles for hazardous liquid pipelines not in HCAs and spacing of a maximum of 1 mile for pipelines at water crossings of greater than 100 feet in width so that the valve is located outside of the flood plain, or the actuators and controls were otherwise unaffected by floodwaters.

In §§ 192.634 and 195.418, PHMSA also proposed that operators would, in HCAs and Class 3 and Class 4 locations for gas pipelines, install RMVs or alternative equivalent technologies upstream and downstream of new construction and replacements longer than 2 contiguous miles regardless of whether the project involved a valve installation.

PHMSA also proposed to modify the IM requirements for both gas and hazardous liquid pipelines to specify that RMVs or alternative equivalent technologies installed to protect HCAs must meet the design, operation, testing, maintenance, and rupture mitigation requirements proposed elsewhere in the NPRM.

2. Comments Received

(i) Spacing

The PST and the NTSB stated the maximum RMV and alternative equivalent technology spacing intervals proposed in the NPRM might not be sufficient to mitigate the consequences of a ruptured pipeline, with the PST expressing concern that 15- and 20-mile spacing is too far, especially for large-diameter pipelines.

For hazardous liquid pipelines, commenters representing the pipeline industry generally did not support a universal mileage threshold for maximum valve spacing without considering the feasibility, practicability, and public safety benefits associated with installing a valve at a particular location. Magellan Midstream Partners L.P. specifically requested PHMSA consider valve spacing that relies on operator programs providing for pipeline-specific evaluations on optimization of valve spacing to reduce the magnitude of potential releases within HCAs. Similarly, commenters representing the hazardous liquid pipeline industry requested PHMSA provide a process for operators to request alternative valve spacing distances for situations where an operator determines the installation of additional valves would not provide additional public safety or where installation is otherwise infeasible.

API, AOPL, and GPA Midstream also suggested that PHMSA's proposal for the maximum valve spacing for HVL pipelines was too stringent at 7 ½ miles and that a 10-mile distance for valves on HVL pipelines would better align PHMSA requirements with standards established in Canada that would be more appropriate for pipelines in the United States. API, AOPL, and GPA Midstream suggested that a 7 ½-mile spacing for HVL pipelines was appropriate only for those pipelines in HCAs. Commenters also noted that the Canadian standard provides operators with a 25 percent spacing flexibility when determining valve locations, and the commenters recommended PHMSA provide a similar allowance.

The PST expressed confusion regarding the NPRM language related to RMV and alternative equivalent technology spacing, suggesting that their interpretation of the proposed regulatory text would allow RMVs and alternative equivalent technology to be spaced at distances greater than the current valve spacing requirements at § 192.179. By contrast, their expectation is that PHMSA's intent is to require more valves at closer spacing intervals than the current rules, or at most, at the same spacing. The PST requested PHMSA clarify whether new valve spacing requirements would be equal to or more stringent than currently required.

At the GPAC meeting on July 22, 2020, the Committee unanimously recommended that PHMSA specify that the spacing requirements in § 192.634 apply to replacement projects covered by § 192.179. At the LPAC meeting on July 23, 2020, the Committee unanimously recommended that PHMSA add a 25 percent tolerance to the spacing of HVL pipelines and add a notification procedure to allow operators of hazardous liquid pipelines to obtain relief from the valve spacing requirements on a case-by-case basis.

(ii) Location

INGAA et al. noted that using an automated valve in a remote area may create a comparatively higher reliability risk than using an automated valve in a more populated area, noting that if a communications failure, power loss, or other malfunction causes an automated valve in a remote area to close unnecessarily, it may take the operator hours to arrive at the valve and restore service, leading to an extended loss of gas supply. They also stated that, in locations where an operator employs an RCV to meet the proposed installation requirement in a Class 1 or Class 2 location, it will take more time for the operator to acquire information about a potential rupture event in remote areas. Further, INGAA et al. stated that operators require significant information about a potential rupture event before making the critical decision to close an RCV, as closing a valve prematurely can have the same disruptive impacts to customers as a rupture.

INGAA et al. also noted that limiting the RMV and alternative equivalent technology installation requirements to pipelines in HCAs and Class 3 and Class 4 locations would also improve the clarity of the rulemaking, stating that the rule, as written, is confusing. INGAA et al. suggested PHMSA revise § 192.179 to clarify that Class 1 and Class 2 locations outside of HCAs do not require RMVs or alternative equivalent technologies to be installed unless the replacement project involves a valve. INGAA et al. noted that this ''opportunistic approach'' appears to have been PHMSA's intent in the proposal, and it differed from their understanding of the rule's application to replacement projects in HCAs and Class 3 and Class 4 locations. Other commenters had similar suggestions and requested PHMSA revise cross-references throughout the rule for clarity. Commenters representing hazardous liquid pipeline operators made a similar comment pertaining to the proposals for hazardous liquid pipelines.

API and AOPL also requested that PHMSA clarify the requirements for the placement of valves near water crossings, recommending that PHMSA base the valve spacing requirements on the size of a 100-year flood plain.

Operators of both gas and hazardous liquid pipelines recommended that PHMSA explicitly state that a shut-off segment must contain the new or replaced HCA segment or Class 3 or Class 4 segment where RMVs or alternative equivalent technologies are installed. Related to shut-off segments, these operators also asked PHMSA to clarify whether operational block valves would be permitted within a shut-off segment, and if an RMV or alternative equivalent technology would need to be the nearest valve to the shut-off segment. Some commenters noted that requiring valves within the endpoints of certain segments might create valve spacing more stringent than the current valve spacing requirement. Further, INGAA et al. questioned if an RMV or alternative equivalent technology is needed at the termination of a pipeline.

For hazardous liquid pipelines, several commenters requested PHMSA clarify what a ''flood plain'' is for the purposes of valve spacing at water crossings, with some commenters suggesting PHMSA specify operators must use the 100-year flood plain. The PST requested PHMSA clarify what ''flood conditions'' meant. Similarly, certain commenters, including Magellan, requested that PHMSA remove the 1-mile limitation on water crossings or provide for alternative spacing if that mile is within the flood plain.

PHMSA also received comments requesting that it remove the proposed requirement to locate valves within 7½ miles of the endpoint of an HCA segment.

At the Committee meetings on July 22 and 23, 2020, the Committees unanimously recommended that PHMSA:

(1) Clarify that replacement projects in non-HCA Class 1 and Class 2 locations do not require RMVs or alternative equivalent technology unless the replacement project involves a valve. Throughout industry public comments, this was what was referred to as the ''opportunistic approach.'' For hazardous liquid pipelines, the LPAC recommended PHMSA revise the rule to clarify the same concept for pipelines in non-HCA locations.

(2) Specify that proposed valve spacing requirements related to pipeline replacements and RMV and alternative equivalent technology installation requirements do not apply to pipelines in non-HCA Class 1 and Class 2 locations.

(3) Specify that a ''shut-off segment'' must contain the newly constructed or replaced HCA or Class 3 or Class 4 pipeline segment.

(4) Specify that RMVs or alternative equivalent technology would not be required at the downstream termination of a pipeline. Further, specify that operational block valves are allowed within a shut-off segment and RMVs and alternative equivalent technology need not be the nearest valve to a shut-off segment.

(5) For hazardous liquid pipelines, specify the 100-year flood plain at hazardous liquid pipeline water crossings.

3. PHMSA Response

(i) Spacing

PHMSA believes the valve spacing it proposed in the NPRM for both gas and hazardous liquid pipelines is appropriate. For new gas pipeline construction, spacing of RMVs and alternative equivalent technology will follow existing requirements at § 192.179(a) determining distance by reference to class location: 2.5-mile intervals in Class 4 locations, 4-mile intervals in Class 3 locations, 7.5-mile intervals in Class 2 locations, and 10-mile intervals in Class 1 locations. For replacement projects on gas pipelines, PHMSA's experience with how operators implement a ''one-class bump'' when a pipeline's class location changes support the final rule's spacing approach. Per the current requirements following a class location change, an operator can base a pipeline's MAOP on a specified design factor multiplied by the test pressure for the new class location as long as the corresponding hoop stress does not exceed certain percentages of the SMYS of the pipe and as long as the pipeline has been tested for a period of 8 hours or longer in accordance with § 192.611(a)(1). This approach has been practical for operators where single-step class location changes occur. Operators performing one-class bumps leave the existing infrastructure in place, which means that, even though the class location has changed, the design standards of the original pipeline are still being used. In addition to wall thickness and steel strength, this applies to the spacing of the valves along the segment as well. For example, operators have been able to use Class 1 spacing standards for valves on a pipeline segment that has changed from a Class 1 to a Class 2 if the operator has followed the appropriate procedures in § 192.611. PHMSA is extending this same methodology to replacement RMV and alternative equivalent technology spacing for gas pipelines by allowing operators to use the maximum valve spacing of a class below the class location of the replacement project. In practice, this means that replacement projects requiring RMVs or alternative equivalent technology in Class 4 locations can have RMVs or alternative equivalent technology spaced at a maximum of 8 miles, replacement projects requiring RMVs or alternative equivalent technology in Class 3 locations can have RMVs or alternative equivalent technology spaced at a maximum of 15 miles, and replacement projects in Class 1 and Class 2 locations can have RMVs or alternative equivalent technology spaced at a maximum of 20 miles. If the RMV or alternative equivalent technology spacing is greater than the spacing for the next class location, a new RMV or alternative equivalent technology is required. Going forward, PHMSA will monitor data in these locations to ensure such spacing does not create an undue risk to people or the environment.

According to PHMSA's data from 2015 to 2019, hazardous liquid pipeline operators have constructed or replaced 4,708 miles of pipeline that is 6 inches or greater in diameter, and they have installed a total of 673 valves on that pipeline mileage for an average of 1 valve for every 7 miles. Therefore, PHMSA does not believe it is onerous to finalize minimum valve spacing standards at every 15 miles for pipeline segments in, or which could affect, HCAs and at every 20 miles for pipeline segments that could not affect HCAs. However, a hazardous liquid pipeline operator may request an exemption from these requirements if it can demonstrate to PHMSA in accordance with the notification procedures in § 195.18, that installing an RMV or alternative equivalent technology as otherwise required by § 195.260 would be economically, technically, or operationally infeasible by reference to factors such as access to communications and power; terrain; prohibitive cost; component and labor availability; ability to secure access rights and necessary permits; and lack of accessibility to operator personnel for installation and maintenance. That notice must also include a safety evaluation of deviation from this final rule's spacing requirements that references technical and safety factors including, but not limited to, the following: Design, construction, maintenance, and operating procedures for pertinent pipeline segments; potential consequences to the environment and the public from a rupture on the pertinent pipeline segments; and mitigation measures (*e.g.,* operating times for isolation valves) in the event of a rupture.

Concerning the proposed spacing for HVL pipeline segments, PHMSA based the valve spacing requirements on the recommended spacing in American Society of Mechanical Engineers (ASME) B31.4, ''Pipeline Transportation Systems for Liquids and Slurries,'' an industry standard that has existed for many decades. PHMSA does not believe that permitting broad tolerance from the HVL valve spacing requirements in a manner similar to the Canadian standard commenters referenced is appropriate, as PHMSA prescribed this valve spacing standard only in high-population areas or other populated areas as defined by § 195.450 where there would be significant populations in need of additional protection. However, in accordance with the LPAC recommendation, PHMSA has provided in this final rule a method for operators to request (in accordance with § 195.18 and subject to PHMSA review) an increase, by 25 percent, of the maximum valve spacing intervals for HVL pipeline segments in high-population areas or other populated areas should the installation of a valve at a particular location not be economically, technically or operationally feasible. Operators would, in connection with that notice, submit a safety evaluation referencing technical and safety factors including, but not limited to, the following: Design, construction, maintenance, and operating procedures for pertinent pipeline segments; potential consequences to the environment and the public from a rupture on the pertinent pipeline segments; and mitigation measures in the event of a rupture. If PHMSA grants the request, the operator is required to keep the records necessary to support such a determination for the useful life of the pipeline.

PHMSA considered the comments regarding the clarity of the proposed valve spacing regulations and the interplay of the various sections of the NPRM when drafting this final rule. PHMSA attempted to simplify the regulatory text by dividing the RMV sections into installation requirements and performance requirements. PHMSA also attempted to consolidate notification requirements broadly by establishing a notification section in part 195, similar to that established in part 192 in the 2019 Gas Transmission Final Rule, and cross-referencing to these sections whenever a notification might be required in the regulations. In addition to reducing the amount of regulatory text, these sections also provide for a more consistent notification process across the regulated community.

(ii) Location

PHMSA notes that the proposed RMV and alternative equivalent technology requirements for gas pipelines in Class 1 and Class 2 locations were intended to apply only to new construction and those replacement projects where 2 or more miles were being replaced and which involved a valve. This was unlike the proposed requirements for gas pipe replacements in excess of 2 miles in HCAs and Class 3 and Class 4 locations, which, as proposed, would have needed upstream and downstream RMVs or alternative equivalent technology regardless of whether the project impacted an existing valve. Therefore, PHMSA is clarifying in this final rule that operators are to take the ''opportunistic'' approach suggested in the comments and are required to install RMVs or alternative equivalent technology during pipe replacement projects in non-HCA Class 1 or Class 2 areas only if the replacement project involves the addition, replacement, or removal of a valve. As previously discussed, this requirement does not apply to those Class 1 or Class 2 locations that have a PIR of 150 feet or less. For hazardous liquid pipelines, the same approach applies to those replacements in non-HCA locations.

Commenters questioned whether a newly constructed or entirely replaced pipeline segment in an HCA was supposed to be included within a shut-off segment for the purposes of the NPRM. PHMSA intended the shut-off segment to include the entire new or replaced pipeline segment in (or, for hazardous liquid lines, which could affect) an HCA and has clarified that intent in the regulatory text of this final rule by stating so explicitly in §§ 192.634 and 195.418. Similarly, some commenters from the hazardous liquid pipeline industry also questioned whether requiring an RMV or alternative equivalent technology within 7½ miles of the endpoint of a hazardous liquid pipeline segment in or which could affect an HCA would ultimately reduce the existing valve spacing. PHMSA did not intend for such a measure to reduce valve spacing and determined that the requirement is duplicative of similar preventative and mitigative requirements set forth in § 195.452. As such, PHMSA has determined that the proposed requirement may have been unnecessary and has deleted it from this final rule.

INGAA et al. also requested PHMSA clarify whether an RMV or alternative equivalent technology is needed at the termination of a pipeline. Per this final rule, an RMV or alternative equivalent technology is needed at the termination of a pipeline, and PHMSA is clarifying that an operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology; PHMSA understands that the logical termination of a pipeline might be within a station, and a valve there could also be used as an RMV or alternative equivalent technology to help isolate a rupture on the pipeline system. Such a valve used as an alternative equivalent technology would not require an advance notification to PHMSA pursuant to §§ 192.18 or 195.18, but, as with any alternative equivalent technology, it must be able to be closed as soon as is practicable and absolutely within 30 minutes after the rupture identification and comply with the applicable provisions of this final rule.

Further, PHMSA also received questions regarding whether operational block valves are permitted within a shut-off segment and whether an RMV or alternative equivalent technology needs to be the nearest valve to the shut-off segment. In the NPRM, PHMSA stated that ''all valves in a shut-off segment'' needed to be RMVs or alternative equivalent technology. However, it was PHMSA's intent that operational block valves be allowed within a shut-off segment as long as the RMV or alternative equivalent technology is within the valve spacing requirements. As such, PHMSA has removed that phrase from this final rule; the section now states the requirements for installing RMVs or alternative equivalent technologies, and it leaves open the possibility that an operator can install additional block valves on a shut-off segment between compliant and appropriately spaced RMVs or alternative equivalent technologies. PHMSA is also clarifying in this final rule that RMVs or alternative equivalent technologies do not need to be the nearest valve to the shut-off segment, and has specifically stated this in the RMV and alternative equivalent technology installation sections at §§ 192.634 and 195.418.

Regarding comments about the installation of RMVs or alternative equivalent technologies near river crossings and flood plains, PHMSA notes that, based on the comments it received, it has made explicit in this final rule that such valves must be installed outside of the 100-year flood plain of the body or bodies of water, or the valves must have actuators and other control equipment installed so as to not be impacted by flood conditions, or the equipment might be elevated to a level where they will not be impacted by flood conditions. PHMSA considers ''flood conditions'' to be where water is at a high enough level near the valve so that it, or the related electronics, would not operate. Flood conditions also can include debris carried by floodwaters that could affect the equipment. For multiple water crossings, PHMSA structured the proposed requirements to provide operators the flexibility to install valves near sites where there are multiple water crossings and where there might be potential access issues between water crossings. This mechanism is consistent with approvals PHMSA has granted operators under the existing authority and process at § 195.260. In this final rule, PHMSA is requiring operators to locate valves upstream and downstream of the first and last of multiple water crossings so that the total distance between the upstream-most valve and the downstream-most valve does not exceed 1 mile, rather than requiring an operator to install RMVs or alternative equivalent technologies on either side of each water crossing where there are multiple water crossings.

G. Valve Status Monitoring

1. Summary of Proposal

In the NPRM, PHMSA proposed to require operators to monitor or otherwise control RMVs or alternative equivalent technologies using remote or on-site personnel. This monitoring or control would include the valve status, the upstream and downstream product pressures, and product flow rates during normal, abnormal, and emergency operations. PHMSA also proposed to require operators be able to monitor the status of valves during rupture events.

2. Comments Received

Several commenters, including INGAA et al., questioned whether remote monitoring of ASVs was required, as those valves would be set to respond automatically to rupture events and not require additional input.

INGAA et al. also requested that PHMSA allow operators to monitor pressure or flow rates in lieu of valve status if they were unable to monitor valve status. PHMSA was also asked to clarify whether operators would need to monitor remotely the flows and pressures through manually operated RMVs after they close. Further, PHMSA was also asked to remove, on efficiency grounds, the proposed requirement for operators to station personnel at a manually operated RMV site for continuous monitoring.

At the Committee meetings on July 22 and 23, 2020, the Committees unanimously recommended that PHMSA specify that an operator does not need to monitor ASV status if the operator can monitor pressures or flows in the pipeline segment to be able to identify and locate a rupture. This differed from the proposed language in that, as worded, an operator would have been required to monitor ASV status in addition to pressures and flows. The Committees also unanimously recommended PHMSA provide a similar allowance for manual valves.

3. PHMSA Response

PHMSA maintains that an operator's ability to monitor the upstream and downstream pressures around RMVs and alternative equivalent technologies is important to identify ruptures effectively and mitigate incidents. As such, PHMSA expects all valves installed as RMVs and as alternative equivalent technologies to monitor pressures upstream and downstream of those valves at all times. However, if operators can monitor upstream and downstream pressures around manual valves that are being used as alternative equivalent technologies or ASVs in real-time so that they can identify and locate a rupture, operators do not need to station personnel at a site where a manually operated alternative equivalent technology has been installed or continually monitor ASV status. In accordance with the Committee recommendations on this issue, PHMSA has specified in this final rule that, if an operator can remotely monitor either pressures or flows in real-time at an ASV or a manual shut-off valve such that they can identify and locate a rupture, the operator does not need to monitor valve status continually, nor are operators required to monitor the pressures on manual valves being used as alternative equivalent technology once those valves are closed in response to a rupture.

H. Class Location Changes

1. Summary of Proposal

In the NPRM, PHMSA proposed to clarify the valve spacing requirements of § 192.179 and to apply the RMV and alternative equivalent technology installation requirement and rupture-mitigation requirements to pipelines where segments of pipe (of any length) were replaced to meet MAOP requirements following a class location change. As proposed, operators would need to install necessary RMVs or alternative equivalent technology within 24 months of the class location change.

2. Comments Received

INGAA et al., GPA Midstream, and the KOGA, expressed concern over the proposed § 192.610 requirements and recommended revisions to the rule language. INGAA et al. indicated that class location change pipe replacements produce minimal pipeline safety benefits because they involve less than 75 miles of transmission pipe per year, and the replaced pipe is often in safe, operable condition.

GPA Midstream called for PHMSA to establish specific valve installation requirements for class-location-related pipeline replacements. They claimed that under PHMSA's interpretation of the current regulations at §§ 192.13(b) and 192.179, operators must comply with valve installation requirements for new pipelines if a segment is replaced in response to a class location change; but that this is contrary to the original intent of the regulations, imposes unreasonable compliance burdens, and discourages pipeline replacements.

INGAA et al. noted that, because the vast majority of class change pipe replacements are less than 2 miles in length, the proposed § 192.610 would require the installation of at least one manual valve for many pipe replacements where the class location changes from a Class 1 to a Class 3. INGAA et al. estimated that it costs $600,000 to $800,000 for an operator to install a new manual valve on an existing pipeline ranging from 24 to 36 inches in diameter, and therefore, the annual cost for installing manual valves under this proposed provision could exceed $100 million per year. Therefore, INGAA et al. suggested that, for class location change pipe replacements that involve less than 2 contiguous miles of pipe but more than 2,000 feet of pipe, PHMSA should provide operators the option to automate an existing upstream and downstream valve so that the distance between such automated valves would not exceed 20 miles, which is the current spacing requirements for valves on pipelines in Class 1 locations. INGAA et al. stated that this would be consistent with the approach that PHMSA has proposed for replacements greater than or equal to 2 contiguous miles in Class 1 and Class 2 locations that are also HCAs. They further stated that retaining the valve spacing requirements for Class 1 locations is appropriate for class location change pipe replacements that do not meet the 2-mile "entirely replaced" definition and will mitigate the need to install a new valve for most class location change pipe replacements.

Similarly, other industry commenters, including GPA Midstream and TC Energy Corporation, stated that PHMSA should exclude short pipe replacements from proposed § 192.610, noting that when an operator is removing a short section of pipe, there may not be an appropriate location in that short area to install a new valve, which can make complying with the valve spacing provisions impractical. Further, these commenters suggested that operators frequently replace short sections of existing pipe to repair potentially injurious conditions found to be affecting that pipe. They stated that many of these maintenance replacements are not "pipe replacement projects," generally only affect small sections of the pipeline, and in some cases, must be conducted immediately to ensure public safety. They argue that operators must be reasonably able to repair such pipeline defects without installing additional valves, stating that requiring all pipe replacements, no matter how small, to comply with valve spacing requirements applicable to new pipe construction would increase cost and regulatory complexity and may reduce an operator's incentive or ability to complete voluntary assessments and remediation. As such, PHMSA was asked to exclude pipe replacements that were less than 2,000 feet from the RMV and alternative equivalent technology installation requirements.

AFPM stated that the requirement to update and install the required valves to match the class location requirements within 24 months of the class location change may not be feasible in all circumstances due to factors outside the control of the operator, such as local permitting. AFPM also suggested that PHMSA should incorporate a process to account for such uncontrollable delays.

At the GPAC meeting on July 22, 2020, the GPAC unanimously recommended that PHMSA specify that the valve spacing in § 192.634 would, pursuant to § 192.610, be applicable to class location changes resulting in the replacement of an aggregate of 2 or more miles of pipe within any 5 contiguous miles, and consider implementing a timeframe of 24 months for compliance from the change in class location. Following discussion of the potential that high installation costs from application of valve spacing requirements to replacement of smaller pipeline segments may discourage pipeline replacement projects, the GPAC also unanimously recommended PHMSA exclude pipeline replacements less than 1,000 feet within 1 contiguous mile from the valve installation requirements. Finally, the Committee unanimously recommended (after discussion of the costs and practical difficulties associated with obtaining land rights necessary to install RMVs on pipelines on segments less than 2 miles in length) that, for pipeline replacements due to class location changes that are between 1,000 feet and 2 miles, PHMSA should allow operators to automate the existing valves with automatic or remote-control actuators and pressure sensors, with a maximum spacing of 20 miles, which they asserted would be consistent with the operational capability proposed in § 192.634.

3. PHMSA Response

PHMSA intended for the RMV and alternative equivalent technology requirements, including those for valve spacing proposed in § 192.634, to be applicable to class location changes for cases where the operator chose to replace pipe to meet the MAOP requirements of the new class location. The proposal was attempting to clarify that, in the event of pipe replacement due to a class location change, operators must install valves that comply with the existing valve spacing requirements at § 192.179(a) for the new class location.[44]

In addition to finalizing that proposal in this final rule for class location-based pipeline replacements of 2 or more miles within any 5 contiguous miles over a 24-month period, PHMSA is also allowing operators to comply with this section by installing or using existing RMVs when a class location changes (*i.e.,* from Class 1 to a Class 2 or a Class 2 to a Class 3) so that the distance between RMVs does not exceed 20 miles. This allowance considers several public comments in addition to a corresponding discussion and recommendation from the GPAC. INGAA et al. noted that the NPRM seemed to require the installation of manual valves on pipelines where the class location had changed. However, this was not PHMSA's intent. The automation of existing valves to protect a pipeline segment where the class location has changed is to provide a higher measure of public and environmental safety than the installation of additional manual valves, given that automated valves will be able to be closed more quickly than manual valves in the event of an emergency.

PHMSA acknowledges that there may be instances where the RMV and alternative equivalent technology installation requirements might not be appropriate for very short sections of pipe that are being replaced under § 192.610. As such, PHMSA is providing in this final rule an exception from the RMV and alternative equivalent technology installation requirements for short pipeline replacements that are less than 1,000 feet in length within 1 contiguous mile. For pipe replacements that occur when class locations change and that range from 1,000 feet to 2 miles in length, PHMSA believes that operators could automate existing valves with RCV or ASV technologies and corresponding pressure sensors that would be consistent with the operational requirements and valve spacing requirements of proposed § 192.634. As discussed in the paragraph above, PHMSA has modified this final rule accordingly.

I. Valve Maintenance

1. Summary of Proposal

In the NPRM, PHMSA proposed to revise §§ 192.745 and 195.420 to require operators perform inspections, maintenance, and drills on RMVs to ensure that they can be closed as soon as practicable but within 40 minutes of identifying a rupture. Among other requirements, PHMSA proposed operators perform point-to-point verification tests for RMVs that are ASVs or RCVs and perform initial validation drills and periodic confirmation drills for manual or locally operated valves an operator identified as RMVs. PHMSA also proposed that operators would be required to identify corrective actions and lessons learned from the validation and confirmation drills and share and implement those lessons learned throughout their pipeline systems. As proposed, operators would be required to repair or remediate inoperable valves within 6 months following a failed drill, with the operator designating a temporary alternate compliant valve within 7 days of a failed drill.

2. Comments Received

Some commenters, including INGAA et al., stated PHMSA should remove the proposed requirement for point-to-point testing because it is already required under the control room management requirements in §§ 192.631 and 195.446. This comment applied to the proposed regulations for both gas and hazardous liquid pipelines.

Operators requested that PHMSA clarify that annual drills are not required for every manual valve and that the drills for ''locally-actuated'' valves would exclude ASVs and RCVs. Further, commenters indicated that PHMSA should provide more specificity regarding the random drill selection process.

INGAA et al. commented that PHMSA should clarify that operators are not required to fully close manual or locally actuated valves during drills. TPA and AFPM expressed this same concern, with AFPM stating that such a requirement might cause significant disruptions when the applicable pipeline is the primary source of feedstock for a major manufacturing facility. INGAA et al. suggested PHMSA allow operators to perform tabletop drills to meet the drill response time requirement.

The Clean Air Council stated that the final rule should include provisions for pipeline operators to perform regular drills to ensure they can comply with the rupture response regulations, test the performance of their equipment, and ensure that pipeline personnel will be trained and skilled in responding to an emergency properly. They noted that while ASVs and RCVs will cut the response time down in a rupture event, having trained operating personnel is also important, stating that PHMSA should include provisions wherein a key responsible individual within the company is identified whose responsibility it is to train new personnel on the rupture response procedures within a certain period of new personnel being hired. They stated that PHMSA should require operators to report on how such training would be conducted and in what period the new individuals are trained, noting that this

[44] *In the Matter of Viking Gas Transmission,* Final Order, C.P.F. No. 32102 (May 1, 1998).

would create accountability for an otherwise unknown factor in pipeline management that would decrease the likelihood that operators may fail in carrying out rupture response procedures in a timely manner. They also noted that with adding in electrical connections and cellular communications with new valves, additional maintenance schedules and procedures will need to be developed for this added complexity. Similarly, the PST supported the proposed requirements for testing, maintenance, drills, and the incorporation of lessons learned into operator procedures.

INGAA et al. stated that PHMSA should reconsider the proposed maintenance requirements for when an RMV or alternative equivalent technology installed under the final rule is unable to achieve the proposed performance standard. Specifically, they suggested PHMSA should revise the NPRM by providing operators 12 months to repair, replace, or install new RMVs when an RMV or alternative equivalent technology is not operating correctly or otherwise cannot achieve the 40-minute response time requirements. This concern was echoed by other industry commenters, who suggested various compliance timeframes. INGAA et al. also stated that PHMSA should allow a notification process when it would not be practicable for an operator to repair or replace an RMV or alternative equivalent technology within 12 months.

GPA Midstream noted that 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. GPA Midstream also stated that a 7-day timeframe may not be sufficient to locate and designate an alternative valve to serve as a substitute for a damaged or otherwise inoperable RMV or alternative equivalent technology. They requested that PHMSA revise the provision to allow 14 days for designating an alternative compliant valve. This concern was echoed by individual operators, who suggested different compliance periods for implementing alternative valve measures.

Other commenters also noted that the proposed 6 months for implementing alternate shut-off valve measures is inadequate because it fails to account for right-of-way acquisition, the time needed to obtain necessary environmental clearance and permits, and extended lead times for the procurement of transmission valves. More specifically, TC Energy requested that PHMSA clarify what is meant by ''alternative compliant valve,'' noting that, because of the proposed 6-month compliance deadline for completing maintenance or replacing a RMV or alternative equivalent technology, it is apparent that ''compliant'' is not intended to refer to proximity or spacing or whether a designated ''alternative valve'' is automated or is manual. TC Energy suggested that PHMSA should direct operators to designate an alternative shut-off valve and document an interim response plan until the primary RMV or alternative equivalent technology is repaired or replaced.

API/AOPL and GPA Midstream also suggested that PHMSA should revise the maintenance procedures to allow operators to obtain an authorized alternative response time.

At the Committee meetings on July 22 and 23, 2020, the Committees unanimously recommended that PHMSA delete the requirement for point-to-point testing because it duplicates requirements in the existing control room management regulations in both parts 192 and 195.

Regarding the drill requirements, the Committees unanimously recommended that PHMSA clarify that annual drills apply only to manually operated valves and involve the manual operation of a local actuator or by hand, and not to ASVs or RCVs. Further, the Committees unanimously recommended specifying that a 25 percent valve closure is sufficient to demonstrate the successful completion of the response time validation drill for manually operated valves.

The Committees also unanimously recommended PHMSA provide operators with a notification process to justify a need to extend the timeframes for repair and establishing alternate RMVs, if necessary. Further, the Committees unanimously recommended PHMSA consider adjusting the timeframe for repairs to 12 months but as soon as practicable, rather than the proposed 6 months. Certain members of the Committees representing the public (including Pipeline Safety Trust) expressed a preference to keep the timeframe for repairs at 6 months. However, other members of the Committees representing industry (including Enbridge, Williams, Consumers Energy, Marathon Pipeline, and PECO) noted that 12 months might be more appropriate given difficulties with supplier access to inventory and procurement issues. Additionally, the Committees unanimously recommended that PHMSA specify that alternative compliant valves identified through this process would not be required to comply with the valve spacing requirements for RMVs.

3. PHMSA Response

PHMSA acknowledges that the proposed point-to-point testing requirements were already a part of the control room management regulations at §§ 192.631 and 195.446. However, PHMSA believes restating the provision in the valve maintenance requirements will provide additional clarity and will improve compliance and enforceability. Therefore, PHMSA has chosen to retain the language in this final rule.

Regarding the proposed manual valve drill requirements, PHMSA intended the annual drills to apply to manually operated valves used as alternative equivalent technology only, and not ASVs or RCVs. PHMSA expects such a drill would include the manual operation of a local actuator or closing the valve via a hand-wheel. PHMSA confirms that annual drills are not required for every manual valve. Rather, an annual drill is required for one randomly selected manual valve in each of the operator's field work units. The way that an operator determines which manual valves would be randomly selected is at the discretion of the operator, but the selection method must be included in an operator's written procedures so it can be subject to inspection.

PHMSA has determined that full closure of valves is not necessary for the purposes of the valve maintenance requirements of this final rule. Accordingly, PHMSA has revised the provision to require, at a minimum, a 25 percent closure of the valve. PHMSA recognizes that overcoming inertia is likely to be the most difficult work in getting a valve to operate. Therefore, PHMSA has determined that a 25 percent or more closure is sufficient to demonstrate the valve's operability and functionality while allowing pipeline operators to maintain service without major interruptions.

Additionally, in this final rule, PHMSA is not allowing operators to perform tabletop drills to verify response times for manually operated valves. PHMSA believes that a tabletop drill would not be sufficient for ensuring that the valve is working, which is the intent of the provision. Operators need to ensure that manual valves being used as an alternative equivalent technology for the purposes of this rulemaking can be arrived at and physically operated so that they function as intended, achieving full closure within the maximum valve-closure time of this rulemaking. A paper exercise cannot effectively confirm real-time travel time to a valve location or the time it will take operator personnel to close a particular valve manually, given conditions that could occur during a rupture.

Regarding the measures operators must take after a failed drill, PHMSA believes that a 7-day timeframe for identifying alternative shut-off measures and a 6-month timeframe for valve repair are appropriate. Because the purpose of an RMV or alternative equivalent technology is to mitigate the consequences of a rupture, should one occur, the longer a valve stays non-functional or the longer it takes an operator to identify alternative measures increases the potential rupture consequences to the area near the impacted pipeline segment. In light of the comments and Committee recommendations for extending the repair period to 12 months given the likely delays involved in scoping and executing required repairs, PHMSA understands that there operators may need repair timeframes longer those identified in the NPRM; PHMSA has, therefore, extended the repair period to 12 months. PHMSA has also provided an advance notification process in this final rule for operators to request (before the repair is undertaken) an extension of that 12-month repair period by demonstrating to PHMSA that repair according to the final rule's timeline will be economically, technically, or operationally infeasible (*e.g.,* by reference to prohibitive costs, difficulty in securing required access rights and permits, long procurement lead times, and component/labor availability). However, PHMSA declines to offer a similar notification process in connection with identification of alternative shut-off measures following a failed drill, as prompt identification of those alternatives are essential for ensuring that the public and the environment are not unprotected from a rupture for extended periods of time.

PHMSA did not intend that any valves operators would identify as an alternative compliant RMV or equivalent technology based on a failed drill would need to comply with the valve spacing requirements of the rulemaking, and PHMSA is not requiring that in this final rule. PHMSA is requiring, however, that any alternative compliant RMV or equivalent technology would contain the entire shut-off segment and comply with the 30-minute valve closure standard of this rulemaking.

Some commenters requested PHMSA enhance the proposed maintenance and drill requirements to cover valve-related specialized equipment and periodic personnel training and management programs. PHMSA notes that these requirements are already included in the Federal Pipeline Safety Regulations, including under the operator qualification and control room management regulations.

J. Failure Investigations

1. Summary of Proposal

In the NPRM, PHMSA proposed to revise the regulations applicable to gas and hazardous liquid pipelines to define the elements that an operator must incorporate when conducting analyses of incidents and other releases and failures involving the activation of RMVs and alternative equivalent technologies, namely ruptures.

The proposed revisions would require the operator to identify potential P&M measures that could be taken to reduce or limit the release volume and damage from similar events in the future. The post-incident or -failure review would address factors associated with this rulemaking, including but not limited to detection and mitigation actions, response time, valve location, valve actuation, and SCADA system performance. Upon completing the post-incident or -failure analysis, the operator would be required to develop and implement the lessons learned throughout its suite of procedures, including in pertinent operator personnel training and qualification programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

2. Comments Received

INGAA et al. stated that PHMSA should remove the references to ''failures'' in § 192.617, as ''failure'' is not defined in parts 191 or 192, and it is unclear if the section accounts for abnormal operations that do not result in a rupture. Similar comments were made by representatives of hazardous liquid pipeline operators, requesting that ''failure'' be changed to ''accident'' to be more consistent with the part 195 regulations.

INGAA et al. added that the prescriptive post-incident requirements proposed in § 192.617 are fit-for-purpose following a rupture but are unnecessary and overly burdensome following an abnormal operation. Other commenters from industry noted that the investigation requirements seemed to be duplicative of existing accident and incident reporting requirements and suggested that PHMSA remove the proposed investigation requirements from the final rule.

GPA Midstream stated that the proposal for operators to prepare and follow procedures for conducting failure and incident investigations should be stated in a new, separate paragraph, and the proposed requirement to incorporate any lessons learned into appropriate part 192 procedures can be consolidated in another paragraph. They further stated that PHMSA could eliminate the other additional language proposed in the section (including sending the failed pipe, component, or equipment to a laboratory for testing), because it is unnecessary. Similarly, Magellan Midstream Partners, L.P., as well as other industry commenters, suggested that PHMSA should remove the proposed requirements for failure analysis because it is not appropriate or effective for an operator to send all failed pipe, components, or equipment for laboratory testing and examination. Further, several of these industry commenters requested PHMSA specify that the implementation of any lessons learned and any additional P&M measures following an incident would be required only if they are reasonable and practicable.

INGAA et al. and GPA Midstream stated that the proposed documentation and recordkeeping requirements for failure investigations are unnecessary, with INGAA et al. stating that the requirements appear to be duplicative of requirements currently under PHMSA's incident reporting requirements. GPA Midstream stated that, to avoid imposing undue burdens on pipeline operators, the senior executive review and lifetime recordkeeping requirements PHMSA proposed should only apply to the final analysis prepared at the conclusion of the investigation rather than preliminary analyses. GPA Midstream and API/AOPL commented that such a requirement would create an additional recordkeeping burden without improving safety, with API requesting PHMSA delete the proposed requirement. AFPM provided similar comments.

The PST stated that PHMSA should amend § 192.617(c) to require that the results of an operator's post-incident review be incorporated into operators' procedures, not just read and kept, as it appears to be proposed. INGAA et al. stated that they support the incorporation of post-incident lessons learned as an important aspect of pipeline safety management systems. However, INGAA et al. added there may be some circumstances where an incident investigation would not yield a change to procedures, for example, some third-party damage incidents, and PHMSA should require operators to incorporate lessons learned and P&M measures only if appropriate and practicable following an incident investigation. TPA generally echoed these remarks.

Further, INGAA et al. stated that they support distribution operators incorporating post-incident lessons learned into their procedures even though the rule stated it only applies to gas transmission and hazardous liquid pipelines, but they recommended PHMSA clarify that the requirements in § 192.617(c) only apply to transmission lines, since the broad definition of ''rupture'' in § 192.3 could lead to § 192.617(c) being interpreted to apply to both gas distribution and gas transmission pipeline incidents.

PST stated that, although the NPRM proposes operators incorporate post-incident lessons into their procedures, the paragraph relating to rupture and valve shut-off incident reviews does not include that same requirement. They added that the section should be amended to include a requirement that the results of the post-incident reviews be incorporated into operator's procedures, not just read and kept.

At the Committee meetings on July 22 and 23, 2020, the Committees unanimously recommended that PHMSA clarify that the implementation of lessons learned and additional P&M measures after incidents are required only where they are found to be reasonable and practicable. Additionally, the GPAC unanimously recommended that PHMSA specify that general failure investigations under these sections would apply to gas distribution pipelines; however, failure investigations specific to RMVs would not apply to gas distribution pipelines.

3. PHMSA Response

PHMSA acknowledges the comments stating that it should clarify the terminology of its proposed regulatory amendments by using defined terms, such as removing the use of the term ''failure'' in favor of ''incident'' or ''accident.'' However, PHMSA notes that existing regulations at § 192.617 address the investigation of failures on gas lines, which is broader than reportable incidents. Similarly, the term ''failure'' is used throughout parts 192 and 195 of the Federal Pipeline Safety Regulations. Therefore, PHMSA has made no changes in this final rule to the phrasing as it was originally proposed in the NPRM, since the term ''failure'' is currently used throughout its regulations.

Other commenters suggested that the failure investigation requirements would duplicate existing incident/accident reporting requirements. PHMSA does not consider the failure investigation requirements that were proposed and the existing incident/accident reporting requirements to be duplicative, as the proposed failure investigation requirements were intended to build on existing failure/accident investigation requirements for gas and hazardous liquid pipelines, and provide more thorough technical evaluation of valve functionality and performance during the mitigation of an incident or accident. PHMSA intended for operators to investigate ''failures,'' as that term is used throughout parts 192 and 195 of its regulations, and as it is defined in ASME B31.8S and ASME B31.4. PHMSA has, however, revised the regulatory text in in this final rule to better convey that intent.

Similarly, some industry commenters, including Magellan, opposed certain requirements in this section, especially with respect to operators sending failed pipe, components, or equipment for laboratory testing and examination. With respect to gas pipelines in particular, PHMSA provides in this final rule additional specificity to the existing regulation at § 192.617, which states that ''each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate [. . .].'' The underlying requirement remained unchanged, and PHMSA has finalized the clarifying changes proposed in the NPRM in a way that will improve the ability to identify and respond to safety issues that could be revealed in such testing and examinations. PHMSA believes that regulatory language in this final rule providing for parallel obligations for hazardous liquid pipelines are similarly essential to its continuing regulatory oversight of the safety of those pipelines.

As for the scope of the proposed failure investigation requirements for gas pipelines, because PHMSA included the amendments in the existing regulations at § 192.617(a) and (b), PHMSA intended those proposed requirements to apply to distribution pipelines, which were already subject to the existing requirements of that section. Because proposed paragraphs (c) and (d) of that section addressed failure investigations specific to the closure of RMVs or alternative equivalent technologies, however, and RMVs or alternative equivalent technologies were and are not required for gas distribution systems in this rulemaking, operators of gas distribution pipelines are not required to comply with those paragraphs as a result of this rule.

INGAA et al. requested PHMSA clarify that the implementation of any post-incident lessons-learned and any additional P&M measures be required only where they are reasonable and practical. PHMSA would not expect operators to implement P&M measures that were clearly unreasonable or impractical. Regarding those measures, PHMSA did not intend to cause any confusion with similar IM requirements by referencing a term that is primarily used in the IM regulations. Subsequently, in this final rule, PHMSA has changed this phrase from ''P&M measures'' to a more general phrase of ''operations and maintenance'' measures to avoid confusion with separate IM-related requirements.

Several comments were submitted regarding senior executive involvement for the certification of failure investigations. PHMSA believes that senior executive certification is essential to ensuring a failure investigation's quality and highlighting the importance of the investigation results and their implementation into operations.

K. 9–1–1 Notification Requirements

1. Summary of Proposal

In the NPRM, PHMSA proposed requirements related to operators responding to pipeline ''emergencies'' that built on existing regulations at §§ 192.615 and 195.402. Specifically, PHMSA proposed to require that an operator's emergency procedures provide for rupture mitigation in response to a rupture event, and that operators contact and maintain liaison with the appropriate public safety answering point (9–1–1 emergency call center) in the event an operator's pipeline ruptures.

2. Comments Received

NAPSR stated that the term ''emergency'' is not defined within part 192, noting that, without a definition for ''emergency,'' operators may make unnecessary notifications to the appropriate fire, police, and public officials, and force responses to minor events instead of real emergencies. NAPSR suggested that if PHMSA is changing this specifically to address ruptures on gas transmission lines, then it may be appropriate for PHMSA to reference ''rupture'' in the final rule language instead of ''emergency.''

TPA stated that the 10-minute requirement for contacting first responders is duplicative and unnecessary, as existing emergency procedures and damage prevention procedures already contain requirements for the timely contact of emergency responders and calls to 9–1–1 numbers. They recommended that PHMSA remove this requirement from the rule. A member of the public agreed that the time to declare a rupture following the first sign of a problem should be no more than 10 minutes, and that emergency services must be notified right away.

The NTSB stated that the proposed changes to the emergency planning regulations do not require immediate and direct notification to local jurisdictions of possible ruptures as recommended by Safety Recommendation P–11–9. They stated that the NPRM's clarifications for when notification is required could unnecessarily delay operators notifying local authorities and possibly exclude some ruptures from the notification requirement, such as distribution systems or portions of transmission systems that do not contain RMVs.

AFPM stated that the language in the proposed sections is unnecessarily prescriptive and the language should be simplified, as the position title or function of the operator personnel that is responsible for contacting the appropriate public safety answering point is immaterial.

AFPM stated that the use of ''may'' in the proposed revision to require notification of ''each government organization that may respond to a pipeline emergency'' vastly expands the universe of events for which operators would have to provide notice and is an unrealistic request. AFPM stated that the operator may not reasonably be able to identify all the possible jurisdictions or agencies that may need to be called upon. As such, AFPM recommended PHMSA allow an operator to identify and coordinate with the agency identified by local or State law as the lead agency in a pipeline emergency, or allow communication with a regional coordinating agency (*e.g.,* Office of Emergency Management) to meet this requirement.

AFPM stated that they support PHMSA's intent to require operators to establish and maintain adequate means of communication with the appropriate public safety officials, as previously established relationships between operators and safety officials could help mitigate the consequences of an incident.

AFPM stated that they believe the use of ''and other public officials'' in the proposed requirements is too vague and potentially expansive. AFPM and INGAA et al. recommended that PHMSA should explicitly note with whom operators should liaise, such as county emergency managers, local emergency planning committees, or 9–1–1 agencies, and limit the requirement to those emergency response agencies with primary jurisdiction for response to a pipeline incident. INGAA et al. stated that this approach would be consistent with the Pipeline Emergency Responder Initiatives that have been developed in several States with the support of PHMSA.

AFPM added that ''notifying the appropriate public safety answering point (9–1–1 emergency call center), as well as fire, police, and other public officials'' is redundant and possibly confusing in jurisdictions where the 9–1–1 center is designated as the single point of emergency services contact. AFPM recommended PHMSA allow 9–1–1 to be the single point of contact for all jurisdictions for which the 9–1–1 center serves as such.

At the Committee meetings on July 22 and 23, 2020, the Committees unanimously recommended that PHMSA state that communication with 9–1–1 applies to all ruptures without exception. For operators of pipelines not located within 9–1–1 service areas or that otherwise have no public safety answering points, the Committees unanimously recommended PHMSA promulgate similar requirements. Further, the Committees unanimously recommended that PHMSA allow operators to establish liaison with the appropriate local emergency response coordinating agencies, such as 9–1–1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity, as was proposed in the NPRM.

The Committees also unanimously recommended that PHMSA limit certain sections of the regulations to emergency preparedness activities and other sections to emergency response activities, rather than combining the two as PHMSA did in the NPRM.

3. PHMSA Response

The NTSB and the PST were concerned that the NPRM, as proposed, could exclude certain ruptures from the notification requirements of this section. PHMSA did not intend to include any exceptions from the 9–1–1 notification requirements of this rulemaking, including for those pipelines where RMV or alternative equivalent technology closure is not required, and does not believe the NPRM was worded as such. Further, PHMSA has modified the language in the NPRM regarding when the 9–1–1 notification obligation has been triggered to reflect the substitution in this final rule of the term ''notification of potential rupture'' for the NPRM's definition of ''rupture''; PHMSA expects this substitution will reduce the time before response and mitigation actions are taken. Ultimately, the requirement in this final rule for 9–1–1 notification applies to all notifications of potential ruptures on all gas and hazardous liquid pipeline systems governed by the emergency planning and procedure requirements at §§ 192.615 and 195.402, respectively.

Industry commenters requested that PHMSA include in the final rule 9–1–1 communication provisions for pipelines that are not located in areas served by 9–1–1 call centers or that have no public safety answering points. The emergency notification requirements in this final rule require operators to establish adequate means of communication with fire, police, and other public officials as needed, regardless of whether they are affiliated with public safety answering points. Operators must determine the jurisdictional areas, responsibilities, resources, and emergency contact numbers for those government organizations that may respond to pipeline emergencies involving their pipeline facilities.

To the points commenters made on liaising with the appropriate local emergency coordinating entities and allowing coordination with a lead agency if recognized by State and local law, PHMSA will note that it did not propose to amend the long-standing requirements about coordinating with local officials, including fire and police officials. The NPRM intended to add the explicit requirement, when applicable, for operators to call 9–1–1 after the notification of a potential rupture. Per this final rule, to meet these requirements of this section, operators may liaise with the appropriate emergency response coordinating agencies, such as 9–1–1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. PHMSA believes that the requirement to liaise with appropriate emergency response coordinating agencies responds to the Committee recommendation for including provisions for operators of pipeline segments outside of 9–1–1 or public safety access point service areas.

L. Other

1. Summary of Proposal

In the NPRM, PHMSA proposed to revise §§ 192.935 and 195.452 to clarify the requirements for conducting ASV and RCV evaluations for HCAs, particularly when RCVs and ASVs are installed as P&M measures associated with improved response times for pipeline ruptures. The proposed amendments would have required that operators be able to evaluate and demonstrate that they could identify a rupture within 10 minutes in accordance with the proposed rupture identification regulations, meet the proposed RMV or alternative equivalent technology closure standard of 40 minutes, and demonstrate compliance with the proposed valve maintenance requirements.

2. Comments Received

Regarding the installation of RMV technology in HCAs under § 192.935, INGAA et al. recommended that PHMSA clarify the decisions operators would be required to make, stating PHMSA proposed in the NPRM that these decisions should consider the swiftness of rupture detection capabilities, not leak detection capabilities. INGAA et al. and other industry commenters also recommended that PHMSA remove the proposed requirements in § 192.935(c) because they appear to be duplicative with the proposed requirements for RMV installation under § 192.634. Similarly, Northern Natural Gas Company recommended that PHMSA remove the proposed requirements at § 192.935 because they are already partially addressed by the investigation of failures and incidents at § 192.617.

The PST supported PHMSA's proposed addition of performance measures for the installation of EFRDs and their use as RMVs under § 195.452. API/AOPL and GPA Midstream suggested that PHMSA should restate that EFRDs installed under the IM regulations must meet the applicable requirements in part 195 for RMVs, as this would simplify the regulatory language.

Northern Natural Gas Company noted that the use of automatic valves may create cybersecurity vulnerabilities. A private citizen echoed this sentiment, stating that PHMSA needs to address cybersecurity issues related to sensors and control systems associated with RMVs, as such issues could reduce the effectiveness of those valves. However, the private citizen noted that Congress has not provided PHMSA, or the U.S. DOT in general, with specific authority to regulate the cybersecurity of pipeline infrastructure. That private citizen suggested that these technologies should be protected from cyber-threats, and the failure of cybersecurity protections should trigger the same reporting requirements that accompany the failure of physical controls.

The Clean Air Council suggested that PHMSA adjust the definition of HCAs to be broader than areas with higher population density, stating they believe that the environmental and historical value of certain locations should be included in an evaluation whether a location is an HCA.

3. PHMSA Response

PHMSA was attempting to update the existing requirements for ASV and RCV analysis in HCAs with the terminology and specific requirements related to RMVs and alternative equivalent technology that were proposed in the NPRM. PHMSA was proposing no new requirements other than that, if operators performed a risk analysis indicating that an ASV or an RCV would provide protection to an HCA or a could-affect HCA pipeline segment, those valves that the operators installed would essentially be RMVs and would need to comply with the 10-minute rupture identification standard, the valve closure time, and the associated maintenance requirements. PHMSA believes that the wording of the section and duplication of those requirements, rather than cross-references, may have confused readers. As such, in this final rule, PHMSA has retained those same requirements while simplifying the language to state that an RMV installed in accordance with §§ 192.935 and 195.452 must comply with all of the other RMV requirements in the respective parts of the regulations.[45]

Regarding cybersecurity issues, PHMSA notes that the recent cyberattack on the Colonial Pipeline underscores the urgency of public-private collaboration to address international cybersecurity threats. PHMSA is working with a coalition of its Federal partners, including the Transportation Security Administration (TSA), to ensure that pertinent regulatory regimes adequately address cybersecurity risks on pipeline infrastructure. PHMSA notes that the TSA recently issued security directives that will enable the Department of Homeland Security (DHS) to better identify, protect against, and respond to threats to critical operators in the pipeline sector. The TSA's initial directive requires critical pipeline owners and operators to report confirmed and potential cybersecurity incidents to the DHS Cybersecurity and Infrastructure Security Agency (CISA) and to designate a Cybersecurity Coordinator, to be available 24 hours a day, 7 days a week. It also requires critical pipeline owners and operators to review their current practices as well as to identify any gaps and related remediation measures to address cyber-related risks and report the results to TSA and CISA within 30 days.[46] A second Security Directive requires owners and operators of TSA-designated critical pipelines to implement specific mitigation measures to protect against ransomware attacks and other known threats to information technology and operational technology systems, develop and implement a cybersecurity contingency and recovery plan, and conduct a cybersecurity architecture design review.

Changing the HCA definition is outside the scope of the rulemaking and would require substantial technical analysis. However, in response to congressional mandates in the ''Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016'' (Pub. L. 114–183) and the 2020 PIPES Act, PHMSA has promulgated an Interim Final Rule (under RIN 2137–AF31) titled ''Pipeline Safety: Coastal Ecological Unusually Sensitive Areas,'' to amend the definition of an ''unusually sensitive area'' in part 195 for hazardous liquid pipelines to include the Great Lakes, coastal beaches, and certain coastal waters explicitly as ecological resources for the purposes of determining whether a pipeline is in, or could affect, an HCA.[47] Further, section 119 of the 2020 PIPES Act requires PHMSA to contract with the National Academy of Sciences (NAS) for development of a study evaluating potential regulatory amendments that would build on this final rule by requiring installation of RMVs on existing natural gas pipelines in HCAs, hazardous liquid pipelines in unusually sensitive areas, and hazardous liquid pipelines in commercially navigable waterways. The NAS committee has been formed and that committee is in the process of planning its activities.[48]

[45] *See* §§ 192.3, 192.9, 192.18, 192.179, 192.610, 192.615, 192.617, 192.634, 192.636, 192.745, and 192.935, as appropriate, for gas transmission and gathering pipelines, and §§ 195.2, 195.11, 195.18, 195.258, 195.260, 195.402, 195.418, 195.419, 195.420, and 195.452, as appropriate, for hazardous liquid pipelines.

[46] *https://www.dhs.gov/news/2021/05/27/dhs-announces-new-cybersecurity-requirements-critical-pipeline-owners-and-operators.*

[47] 86 FR 73173 (Dec. 27, 2021).

[48] NAS, ''Criteria for Installing Automatic and Remote-Controlled Shutoff Valves on Existing Gas and Hazardous Liquid Transmission Pipelines'' (last visited Nov. 23, 2021).

IV. Section-by-Section Analysis of Changes to 49 CFR Part 192 for Gas Pipelines

§ 192.3 Definitions

Section 192.3 provides definitions for various terms used throughout part 192. Most of the requirements of this final rule would be triggered by an operator identifying a rupture following the notification of a potential rupture. Therefore, PHMSA is amending § 192.3 to define the ''notification of potential rupture'' in terms of notification of, or observation by, an operator of indicia specified in § 192.635 of an unintentional or uncontrolled release of a large volume of gas from a pipeline.

Once an operator is notified of a potential rupture, they must identify a rupture, if one exists. Therefore, PHMSA has established a concept of ''rupture identification'' to mean the point when a pipeline operator has sufficient information reasonably to determine that a rupture occurred. PHMSA believes this would occur following a ''notification of potential rupture,'' as that term has been defined in this rulemaking, given that the operator would have been notified or would have had notice of some indicia of a potential rupture per § 192.635. The final rule at § 192.615 requires that operators must document, in their operations manual or written procedures, their method for rupture identification. An operator, after identifying a rupture, would be required to close the RMVs or alternative equivalent technologies necessary to isolate the ruptured pipeline segment.

As a part of this rulemaking, operators are required to install RMVs or alternative equivalent technology on certain pipeline segments, including those that are ''entirely replaced onshore pipeline segments.'' RMVs are defined in this rulemaking to mean ASVs or RCVs that a pipeline operator uses to minimize the volume of gas released from the pipeline and to minimize the consequences of a rupture. PHMSA has defined entirely replaced onshore transmission pipeline segments to mean those pipeline replacement projects where 2 or more miles of pipeline have been replaced within any length of 5 contiguous miles of pipeline during any 24-month period.

§ 192.9 What requirements apply to gathering lines?

In this final rule, PHMSA has clarified that the RMV and alternative equivalent technology requirements being promulgated apply to Type A gas gathering pipelines (not Types B or C gathering lines), as these pipelines typically have risk profiles similar to transmission pipelines.

§ 192.18 How To Notify PHMSA

In this final rule, operators can notify PHMSA in advance of their intent to use a technology, method, or compliance timeline that differs from that listed in the regulations, when the option for notification is specifically provided. PHMSA retains discretion under § 192.18 to reject, as appropriate, such requests. Accordingly, PHMSA has revised this section to provide for a consistent notification procedure across part 192 whenever an operator is required to notify PHMSA as a part of a requirement.

§ 192.179 Transmission Line Valves

In this final rule, PHMSA is requiring the installation of RMVs or alternative equivalent technologies on certain gas pipelines. This section specifies that operators must install RMVs, or alternative equivalent technologies, on onshore gas pipeline segments with diameters greater than or equal to 6 inches that are newly constructed, or meet the definition of entirely replaced onshore transmission pipeline segments, after April 10, 2023. RMVs and alternative equivalent technologies installed in accordance with this section must meet the existing valve spacing requirements of this section, and all RMVs and alternative equivalent technologies installed in accordance with this section must meet the operational requirements outlined in § 192.636.

These installation requirements do not apply to those pipeline segments that are in Class 1 or Class 2 locations and that have a PIR of less than or equal to 150 feet. Further, the installation requirements for entirely replaced onshore pipeline segments only apply to those pipeline replacement projects that involve the addition, replacement, or removal of a valve.

If an operator seeks to install alternative equivalent technology pursuant to this section, the operator must, in advance of such installation, submit a notification making such a request to PHMSA in accordance with § 192.18. The operator must include in that notification a site-specific technical and safety evaluation demonstrating that technology provides an equivalent level of safety to an RMV by reference to factors including, but not limited to, the following: Design, construction, maintenance, and operating procedures; technology design and operational characteristics such as operation times (closure times for manual valves); service reliability and life; accessibility to operator personnel; nearby population density; and potential consequences to the environment and the public.

If an operator requests use of manual valves as an alternative equivalent technology, the notification submitted to PHMSA must also demonstrate the site-specific economic, technical, or operational infeasibility of installing an RMV (*e.g.,* by reference to factors such as access to communications and power; terrain; prohibitive cost; labor and component availability; ability to secure required land access rights and permits; and accessibility to operator personnel for installation and maintenance).

An operator may also submit for PHMSA review, in accordance with the notification procedures in § 192.18, a project-specific request for extension of the compliance deadline in this section. That notification must demonstrate installation of an RMV or alternative equivalent technology in connection with near-term construction and replacement projects would be economically, technically, or operationally infeasible (*e.g.,* by reference to prohibitive economic costs, difficulty in securing access rights, component/labor availability and procurement lead times, or permitting requirements).

An operator that replaces pipeline segments is not required to meet the valve spacing requirements of this section if the distance between each point on the pipeline and the nearest valve does not exceed 4 miles in Class 4 locations, 7½ miles in Class 3 locations, and 10 miles in all other locations.

§ 192.610 Change in Class Location: Change in Valve Spacing

This section specifies RMV and alternative equivalent technology requirements when a class location changes. In cases where pipeline segments are entirely replaced, as that term is defined in § 192.3, to meet the maximum allowable operating pressure in accordance with requirements for class location changes under §§ 192.611, 192.619(a), and 192.620, then an operator must install valves, including RMVs or alternative equivalent technology, as necessary to comply with this part. An operator must install such valves within 24 months of the class location change.

If an operator replaces less than 2 miles of pipe in a length of 5 contiguous miles of pipe during a 24-month period to comply with the maximum allowable operating pressure requirements after a class location changes, the operator must either: (1) Comply with the valve spacing requirements at § 192.179(a), or (2) install or use RMVs or alternative equivalent technology so that the entirety of the replaced pipeline segment is between 2 RMVs or alternative equivalent technology and so that the distance between those valves does not exceed 20 miles. Operators are not required to comply with this section if they replace less than 1,000 feet of pipe within any single contiguous mile within any 24-month period to comply with a class location change.

§ 192.615 Emergency Plans

In this final rule, PHMSA revised paragraphs (a)(2), (a)(6), (a)(8), (a)(11), and (a)(12) and the introductory text of (c) in § 192.615 to require that emergency procedures provide for rupture mitigation in response to a rupture event. PHMSA is also requiring that operators maintain liaison with and contact the appropriate public safety answering point (*i.e.,* 9–1–1 emergency call center), if such a service is available, in the event of pipeline emergencies. In lieu of communicating with individual fire, police, or other public entities, operators may instead establish liaison with appropriate local emergency coordinating agencies, such as 9–1–1 emergency call centers or county emergency managers, as appropriate.

PHMSA is requiring, through this final rule, that operators learn the responsibilities, resources, jurisdictional areas, and emergency contact telephone numbers for each Federal, State, and local government organization that may respond to a pipeline emergency involving their pipeline facilities, and inform such officials of the operator's ability to respond to and communicate during pipeline emergencies. PHMSA has not changed the existing requirements for operators to maintain liaison with fire, police, and other public officials, as appropriate.

In conjunction with the definition of the ''notification of potential rupture,'' PHMSA has in this final rule codified at § 192.615(a)(12) language within the NPRM expressing its expectation that operators will, upon notification of a potential rupture, identify whether there is indeed a rupture by reference to their written procedures. At a minimum, the procedures must specify the sources of information, operational factors, and other criteria that the operator will use to evaluate a notification of a potential rupture as an actual rupture. Those written procedures should also incorporate procedures for waiver of any requirements for specific pipeline personnel to conduct on-scene investigation of a potential rupture if an operator receives one or more of the following: Multiple or recurring instrument indications (pressure readings, alarms, etc.) of potential ruptures; pressure drops significantly in excess of the minimum thresholds in § 192.635(a)(1); or reports of rupture indicia from on-scene, credible sources (*e.g.,* on or off-duty pipeline operator personnel, sheriff or police officers, fire department personnel, or other emergency response personnel).

§ 192.617 Investigation of Failures and Incidents

In this final rule, PHMSA has revised § 192.617 to define the elements that an operator must incorporate when conducting a post-event analysis of ruptures and other failure events involving the activation of RMVs or alternative equivalent technology.

The revision requires the operator to identify potential preventive and mitigative measures that could be taken to reduce or limit the release volume and damage from similar events in the future. The post-incident or -failure review would include, but not be limited to, detection and mitigation actions, response time, valve location, valve actuation, and SCADA system performance. Upon completing the post-event analysis, the operator must develop and implement the lessons learned throughout its suite of procedures, including in pertinent operator personnel training and qualification programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications. In accordance with this section, an operator must also complete a summary of the post-incident or -failure review within 90 days of the incident. The operator must conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. The final post-incident summary and all other reviews and analyses produced under the requirements of this section must be reviewed, dated, and signed by the operator's appropriate senior executive officer. Further, an operator must keep the final post-incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned for the useful life of the pipeline. The requirements to produce a summary report are not applicable to gas distribution and Types B and C gathering pipelines.

PHMSA has also modified the existing failure and incident investigation requirements at § 192.617 to require operators subject to that provision to incorporate lessons learned from those investigations into their written procedures, including personnel training and qualification programs, and design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications. PHMSA has otherwise not made changes to the existing requirements in this section for operators of gas pipelines to establish procedures for analyzing incidents and failures.

§ 192.634 Transmission Lines: Onshore Valve Shut-Off for Rupture Mitigation

This section requires operators to install and use RMVs or alternative equivalent technology on newly constructed and entirely replaced onshore gas pipeline segments with diameters of 6 inches or greater. Such valves would be required to be operational within 14 days following placing the pipeline segment into service unless the operator has submitted for PHMSA review, in accordance with § 192.18, a notification that operation of the RMV or alternative equivalent technology within that 14-day timeframe is not economically, technically, or operationally feasible. An operator may also submit for PHMSA review, in accordance with the notification procedures in § 192.18, a request for extension of the valve installation compliance deadline requirements of § 192.179 and this section demonstrating that installation of an RMV or alternative equivalent technology in connection with particular near-term construction and replacement projects would be economically, technically, or operationally infeasible (*e.g.,* by reference to prohibitive costs, difficulty in securing required access rights and permits, and component/labor availability).

For the purposes of the RMV and alternative equivalent technology installation requirements, PHMSA created a definition for a ''shut-off segment,'' which is a pipeline segment that is entirely located between at least two RMVs or alternative equivalent technologies. If any crossover or lateral pipe for commodity receipts or deliveries connects to the shut-off segment between the upstream-most and downstream-most RMVs or alternative equivalent technologies, the shut-off segment also extends to valves on those crossover connections or laterals used for receipt or delivery so that, when all valves are closed, there is no flow path for commodity to be transported from outside the shut-off segment to the rupture site. Laterals that connect to shut-off segments and that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies installed at locations other than mainline receipt or delivery points. A shut-off segment can include multiple HCAs, and operators are not required to select the closest valve to the shut-off segment as an RMV or alternative equivalent as long as the proper valve spacing is maintained.

The requirements of this section apply to all applicable pipe replacement projects, even those that do not otherwise directly involve the addition or replacement of a valve. Consistent with the requirements for RMV and alternative equivalent technology installation, this section does not apply to pipe segments in Class 1 or Class 2 locations that have a PIR less than or equal to 150 feet.

This section also establishes valve spacing for RMVs and alternative equivalent technologies installed in accordance with this section, where the distance between such RMVs and alternative equivalent technologies must not exceed 8 miles in Class 4 locations, 15 miles in Class 3 locations, and 20 miles in all other locations.

Operators using a manual valve as an alternative equivalent technology in lieu of an RMV for the purposes of this section must appropriately locate personnel to ensure valve shut-off in accordance with this section and the RMV performance requirements in § 192.636.

§ 192.635 Notification of Potential Rupture

In this section, PHMSA provides the criteria for a ''notification of potential rupture,'' as that term is defined in § 192.3.

§ 192.636 Transmission Lines: Valve Capabilities

In this section, PHMSA establishes the operational requirements for RMVs and alternative equivalent technologies. Following the ''notification of potential rupture,'' an operator must, after identifying a rupture, close such valves as soon as practicable, but no later than within 30 minutes (measured from rupture identification). Operators may request to plan to leave RMVs or alternative equivalent technologies open for longer than 30 minutes following rupture identification if the operator previously has coordinated the plan with appropriate local emergency responders, notified PHMSA, and adequately demonstrated to PHMSA that closing such valves or technologies would be detrimental to public safety.

RMVs and alternative equivalent technologies must be capable of being monitored or controlled by remote or on-site personnel, operated during all operating conditions, and monitored for valve status. Operators using ASVs as RMVs do not need to monitor those valves remotely if the operator has the capability to monitor pressures or gas flow rate on the pipeline in order to identify and locate a rupture pursuant to the requirements of this rulemaking.

Operators of pipelines in Class 1, non-HCAs may request, within their notification under § 192.18 seeking PHMSA review for installation of manual valves as alternative equivalent technologies as contemplated by this final rule, an exemption from the valve operation requirements of § 192.636(b). Operators seeking such an exemption must provide for PHMSA review within that notification the closing times for those manual valves.

§ 192.745 Valve Maintenance: Transmission Lines

In this final rule, PHMSA is revising § 192.745 by adding paragraphs (c), (d), and (e) to incorporate the maintenance, inspection, and operator drills required to ensure operators can close an RMV or alternative equivalent technology as soon as practicable, but no more than 30 minutes, after identification of a rupture. PHMSA is finalizing initial validation drill requirements and requirements for periodic validation tests for any manually or locally operated valve installed as an alternative equivalent technology in lieu of an RMV. Operators are not required to close the valves fully during such drills; a closure of 25 percent, at a minimum, is sufficient to be compliant, unless the operator has information that requires additional closure requirements for the valve to be compliant with the requirement. If the 30-minute-maximum closure time cannot be achieved during the drill, the operator must revise their response efforts and repair any valves to achieve compliance as soon as practicable but no later than 12 months after the drill. Operators may request, pursuant to the notification procedure at § 192.18, an extension of the 12-month repair timeline if such repair within 12 months would be economically, technically, or operationally infeasible (*e.g.,* by reference to prohibitive costs, difficulty in securing required access rights and permits, long procurement lead times, and component/labor availability). Alternative valve shut-off measures must be in place within 7 days of a failed drill. In accordance with § 192.631(c) and (e), operators must also conduct a point-to-point verification between SCADA displays, sensors, communications equipment, and any RCVs installed in accordance with §§ 192.179 or 192.634.

Per this final rule, each operator is required to identify corrective actions and lessons learned resulting from the validation and confirmation drills and share and implement them across its entire network of pipeline systems.

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

In this final rule, PHMSA is revising § 192.935(c) to clarify the requirements for conducting RMV evaluations for HCAs, particularly when an operator installs such valves as preventive and mitigative measures to improve response times for pipeline ruptures and mitigate the consequences of a rupture. RMVs installed in accordance with this section must meet all other RMV requirements in part 192.

PHMSA is also requiring that risk analyses and assessments conducted under this section be reviewed by the operator and certified by a senior executive of the company. Review and certification must occur at least once per calendar year, with the period between reviews not to exceed a period of 15 months, and must also occur within 3 months of an incident or a safety-related condition. Such analyses and assessments must consider new or existing operational and integrity matters that could affect rupture-mitigation processes and procedures.

V. Section-by-Section Analysis for Changes to 49 CFR Part 195 for Hazardous Liquid Pipelines

§ 195.2 Definitions

Section 195.2 provides definitions for various terms used throughout part 195. Most of the requirements of this final rule would be triggered by an operator identifying a rupture following the notification of a potential rupture. Therefore, PHMSA is amending § 195.2 to define the ''notification of potential rupture'' in terms of notification of, or observation by, an operator of indicia specified in § 195.417.

Once an operator is notified of a potential rupture, they must identify the rupture, if one exists. Therefore, PHMSA has established a concept of ''rupture identification'' to mean the point when a pipeline operator has sufficient information reasonably to determine that a rupture occurred. The final rule at § 195.402 requires that operators must document, in their operations manual, their method for rupture identification. An operator, after identifying a rupture, would be required to close the RMVs or alternative equivalent technologies necessary to isolate the ruptured pipeline segment.

As a part of this rulemaking, operators are required to install RMVs or alternative equivalent technologies on certain pipeline segments, including those that are ''entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments.'' RMVs are defined in this rulemaking to mean ASVs or RCVs that a pipeline operator uses to minimize the volume of hazardous liquid or carbon dioxide released from the pipeline and to minimize the consequences of a rupture. PHMSA has defined entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments to mean those pipeline replacement projects where 2 or more miles of pipeline have been replaced within any length of 5 contiguous miles of pipeline during any 24-month period.

§ 195.11 What is a regulated rural gathering line and what requirements apply?

Section 195.11 contains the requirements for regulated rural gathering pipelines carrying hazardous liquid or carbon dioxide. In this final rule, PHMSA is specifying that the only regulated rural gathering pipelines that are required to install RMVs or alternative equivalent technologies are those pipelines subject to § 195.260(e), which requires the installation of RMVs or alternative equivalent technologies on pipelines that span water crossings more than 100 feet wide, from high water mark to high water mark.

§ 195.18 How To Notify PHMSA

In this final rule, operators can notify PHMSA in advance of their intent to use a technology, compliance timeline, or method that differs from that listed in the regulations, when that option is specifically provided in the regulatory text. PHMSA retains discretion under § 195.18 to reject, as appropriate, such requests. Accordingly, PHMSA has revised this section to provide for a consistent notification procedure across part 195 whenever an operator is required to notify PHMSA as a part of a requirement of this final rule. This provision is similar to the notification procedure created for part 192.

§ 195.258 Valves: General

In this final rule, PHMSA is requiring the installation of RMVs or alternative equivalent technologies on certain pipelines. This section specifies that operators must install RMVs, or alternative equivalent technologies, on onshore hazardous liquid or carbon dioxide pipeline segments with diameters greater than or equal to 6 inches that are constructed, or meet the definition of entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments, after April 10, 2023. RMVs and alternative equivalent technologies installed in accordance with this section must meet the existing valve spacing requirements of § 195.260, and all alternative equivalent technologies installed in accordance with this section must meet the operational requirements of RMVs outlined in § 195.419. These installation requirements for entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments only apply to those pipeline replacement projects that involve the addition, replacement, or removal of an existing valve.

If an operator seeks to install alternative equivalent technology pursuant to this section, the operator must, in advance of such installation, submit a notification making such a request to PHMSA in accordance with § 195.18. The operator must include in that notification a site-specific technical and safety evaluation demonstrating that technology provides an equivalent level of safety to an RMV by reference to factors including, but not limited to, the following: Design, construction, maintenance, and operating procedures; technology design and operational characteristics such as operation times (closure times for manual valves); service reliability and life; accessibility to operator personnel; nearby population density; and potential consequences to the environment and the public.

If an operator requests use of manual valves as an alternative equivalent technology, the notification submitted to PHMSA must also demonstrate site-specific economic, technical, or operational infeasibility of installing an RMV (*e.g.,* by reference to factors such as access to communications and power; terrain; prohibitive cost; labor and component availability; ability to secure required land access rights and permits; and accessibility to operator personnel for installation and maintenance.

An operator may also submit for PHMSA review, in accordance with the notification procedures in § 195.18, a project-specific request for extension of the compliance deadline in this section. That notification must demonstrate installation of an RMV or alternative equivalent technology in connection with near-term construction and replacement projects would be economically, technically, or operationally infeasible (*e.g.,* by reference to prohibitive economic costs, difficulty in securing required access rights and permits, and component/labor availability).

§ 195.260 Valves: Location

Section 195.260 finalizes requirements for the location of valves on newly constructed and entirely replaced onshore hazardous liquid or carbon dioxide pipelines, where such pipeline segments installed after April 10, 2023, must have valve spacing that does not exceed 15 miles for pipelines that could affect HCAs, as that term is defined in § 195.450. For those pipelines that could not affect HCAs, the valve spacing requirements for such pipelines cannot exceed 20 miles. An operator installing valves that protect HCAs must install those valves at locations determined through the operator's process for identifying preventive and mitigative measures established pursuant to § 195.452(i) and Appendix C, Section B of part 195. An operator may submit for PHMSA review, in accordance with the notification procedures in § 195.18, a request for extension of the compliance deadline for valve installation and spacing in this section. That notification must demonstrate that the compliance timeline for valve spacing required by this final rule would be economically, technically, or operationally infeasible in connection with particular near-term construction and replacement projects (*e.g.,* by reference to factors such as access to communications and power; terrain; prohibitive cost; component and labor availability; ability to secure access rights and necessary permits).

PHMSA has also revised the valve location requirements for those pipelines that cross waterways that are more than 100 feet wide from high water mark to high water mark. Accordingly, in this final rule, operators must install valves at locations outside of the 100-year flood plain or otherwise install valves that are equipped with control equipment that would not be made inoperable by flood conditions.[49] Additionally, the maximum spacing between valves protecting multiple

[49] A 100-year flood plain is an area that has a 1-in-100 chance of having a flood event that could be equaled or exceeded in any 1 year, and it has an average recurrence interval of 100 years. 100-year flood plains are determined by the Federal Emergency Management Agency, which operates the official flood hazard Mapping Service Center in support of the National flood insurance program, and they offer flood zone maps online. If another agency, such as a State authority, is responsible for determining the 100-year flood plain for the area where the pipeline is located, the operator should use those resources and documents.

adjacent water crossings cannot exceed 1 mile.

In this section, PHMSA has also finalized spacing requirements for HVL pipelines in high-population areas or other populated areas, as defined in § 195.450. These pipelines must have a maximum valve spacing of 7½ miles if they have been constructed or where 2 or more miles of pipeline have been replaced within a span of 5 contiguous miles within a 24-month period, following April 10, 2023. The maximum valve spacing for HVL pipelines can be increased by 1.25 times the distance to a maximum of a 9⅜-mile spacing if the operator submits for PHMSA review, in accordance with § 195.18, within its notification (1) an evaluation of the safety of the alternative spacing, referencing technical and safety factors including, but not limited to, the following: Design, construction, maintenance, and operating procedures for pertinent pipeline segments; potential consequences to the environment and the public from a rupture on the pertinent pipeline segments; and mitigation measures in the event of a rupture; and (2) a demonstration that the installation of a valve at the otherwise-required spacing is economically, technically or operationally infeasible (*e.g.,* by reference to factors such as access to communications and power; terrain; prohibitive cost; labor and component availability; ability to secure required land access rights and permits; and accessibility to operator personnel for installation and maintenance).

Additionally, operators may notify PHMSA, using the procedure at § 195.18, if, in particular cases, the valve installation or valve spacing requirements of certain paragraphs of this section are not necessary to achieve an equivalent level of safety at a particular site. That notification must include a supporting technical and safety evaluation referencing technical and safety factors including, but not limited to, the following: Design, construction, maintenance, and operating procedures for pertinent pipeline segments; potential consequences to the environment and the public from a rupture on the pertinent pipeline segments; and mitigation measures in the event of a rupture.

§ 195.402 Procedural Manual for Operations, Maintenance, and Emergencies

In this final rule, PHMSA revised § 195.402 to require that emergency procedures provide for rupture mitigation in response to a rupture event. PHMSA is also requiring that operators maintain liaison with and contact the appropriate public safety answering point (*i.e.,* 9–1–1 emergency call center), if such a service is available, in the event of pipeline emergencies. In lieu of communicating with individual fire, police, or other public entities, operators may instead establish liaison with appropriate local emergency coordinating agencies, such as 9–1–1 emergency call centers or county emergency managers, as appropriate.

PHMSA is requiring, through this final rule, that operators must learn the responsibilities, resources, jurisdictional areas, and emergency contact telephone numbers for each Federal, State, and local government organization that may respond to a pipeline emergency involving their pipeline facilities, and inform such officials of the operator's ability to respond to and communicate during pipeline emergencies. PHMSA has not changed the existing requirements for operators to maintain liaison with fire, police, and other public officials, as appropriate.

In conjunction with the definition of a ''notification of potential rupture,'' PHMSA has in this final rule codified at § 195.402(e)(4) language within the NPRM expressing its expectation that operators will, upon notification of a potential rupture, identify whether there is indeed a rupture by reference to written procedures. At a minimum, the procedures must specify the sources of information, operational factors, and other criteria that the operator will use to evaluate a notification of a potential rupture as an actual rupture. Those written procedures should also incorporate procedures for waiver of any requirements for specific pipeline personnel to conduct on-scene investigation of a potential rupture if an operator receives one or more of the following: Multiple or recurring instrument indications (pressure readings, alarms, etc.) of potential ruptures; pressure drops significantly in excess of the minimum thresholds in § 195.417(a)(1); or reports of rupture indicia from on-scene, credible sources (*e.g.,* on or off-duty pipeline operator personnel, sheriff or police officers, fire department personnel, or other emergency response personnel).

Further, PHMSA has revised this section to define the elements that an operator must incorporate when conducting a post-accident or -failure analysis of ruptures and other accident and failure events involving the activation of RMVs or alternative equivalent technologies. PHMSA has not made changes, otherwise, to the existing requirements in this section for operators of hazardous liquid and carbon dioxide pipelines to establish procedures for analyzing accidents and failures.

The revision requires the operator to identify potential preventive and mitigative measures that could be taken to reduce or limit the release volume and damage from similar events in the future. The post-incident review would include but not be limited to detection and mitigation actions, response time, valve location, valve actuation, and SCADA system performance. Upon completing the post-accident analysis, the operator must develop and implement the lessons learned throughout its suite of procedures, including in pertinent operator personnel training and qualification programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications. In accordance with this section, an operator must also complete a summary of the post-incident review within 90 days of the incident, and, while the investigation is pending, conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. The final post-incident summary and all other reviews and analyses produced under the requirements of this section must be reviewed, dated, and signed by the operator's appropriate senior executive officer. Further, an operator must keep the final post-incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned for the useful life of the pipeline. The requirements to produce a summary report are not applicable to gas distribution pipelines.

PHMSA has also modified the failure and accident investigation requirements at § 195.402 to require operators subject to that provision to incorporate lessons learned from those investigations into their written procedures, including personnel training and qualification programs, and design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

§ 195.417 Notification of Potential Rupture

In this section, PHMSA provides the criteria for a ''notification of potential rupture,'' as that term is defined in § 195.2.

§ 195.418 Valves: Onshore Valve Shut-Off for Rupture Mitigation

This section requires operators to install or use RMVs or alternative equivalent technologies on many newly constructed and entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments with diameters of 6 inches or greater. Such valves would be required to be operational within 14 days of placing the pipeline segment into service unless the operator has submitted for PHMSA review, in accordance with the notification procedure at § 195.18, a request for extension demonstrating that operation of that RMV or alternative equivalent technology within that 14-day timeframe is not economically, technically, or operationally feasible. The requirements of this section apply to all applicable pipe replacement projects, even those that do not otherwise directly involve the addition or replacement of a valve.

For the purposes of the RMV and alternative equivalent technology installation requirements, PHMSA created a definition for a ''shut-off segment,'' which is a pipeline segment that is entirely located between at least two RMVs or alternative equivalent technologies. If any crossover or lateral pipe for commodity receipts or deliveries connects to the shut-off segment between the upstream-most and downstream-most RMV or alternative equivalent technology, the shut-off segment also extends to valves on those crossover connections or laterals, whether those laterals are used for receipt or delivery, so that, when all valves are closed, there is no flow path for commodity to be transported from outside the shut-off segment to the rupture site. Laterals that connect to shut-off segments and that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies installed at locations other than mainline receipt or delivery points. A shut-off segment can include multiple HCAs, and operators are not required to select the closest valve to the shut-off segment as an RMV or alternative equivalent technology as long as the proper valve spacing is maintained.

This section also establishes valve spacing for RMVs or alternative equivalent technology installed in accordance with this section, where the distance between such RMVs and alternative equivalent technologies must not exceed 15 miles for lines carrying non-HVLs, and 7½ miles for lines carrying HVLs. The maximum valve spacing intervals for RMVs and alternative equivalent technologies on pipelines carrying HVLs may be increased by 1.25 times the spacing distance to a maximum of 9⅜ miles, subject to review by PHMSA of an operator's request demonstrating that installation of a valve at a 7-mile to a 7½-mile spacing is economically, technically, or operationally infeasible.

Operators using a manual valve as an alternative equivalent technology in lieu of an RMV for the purposes of this section must appropriately designate and locate personnel near the valve to ensure valve shut-off in accordance with this section and the RMV performance requirements in § 195.419.

§ 195.419 Valve Capabilities

In this section, PHMSA establishes the operational requirements for RMVs and alternative equivalent technologies installed pursuant to this final rule. Following a ''notification of potential rupture,'' an operator must identify whether a rupture is occurring on their system and close RMVs and alternative equivalent technologies as soon as practicable, but no later than within 30 minutes of rupture identification, or, if applicable, no later than the shut-down times used in calculating a worst-case discharge in accordance with § 194.105(b)(1), whichever shut-off time is a shorter time interval.

RMVs and alternative equivalent technologies must be capable of being monitored or controlled by remote or on-site personnel, operated during all operating conditions, and monitored for valve status. Operators using ASVs as RMVs do not need to monitor those valves remotely if the operator has the capability to monitor pressures or product flow rate on the pipeline in order to identify and locate a rupture.

Operators of pipelines in non-HCAs or of segments that could not affect an HCA may submit for PHMSA review, within a notification under § 195.18 requesting installation of manual valves as an alternative equivalent technology, an exemption from the valve operation requirements of § 195.419(b). An operator seeking such an exemption must provide for PHMSA review within that notification the closing times for those manual valves.

§ 195.420 Valve Maintenance

In this final rule, PHMSA is revising § 195.420 to incorporate the maintenance, inspection, and operator drills required to ensure operators can close an RMV or alternative equivalent technology installed under this final rule as soon as practicable, but within 30 minutes following rupture identification or within their shut-down times used in calculating the worst-case discharge in accordance with § 194.105(b)(1), whichever is a shorter time interval. PHMSA is finalizing initial validation drill requirements and requirements for periodic confirmation drills for any manually or locally operated valve used as an alternative equivalent technology in lieu of an RMV. Operators are not required to close the valves fully during such drills; a closure of 25 percent, at a minimum, is sufficient to be compliant. If the 30-minute-maximum closure time cannot be achieved during the drill, or shorter time pursuant to its part 194 worst-case discharge calculations, the operator must revise their response efforts and repair any valves to achieve compliance as soon as practicable but no later than 12 months after the drill. Operators may request, pursuant to the notification procedure at § 195.18, an extension of the 12-month repair timeline if such repair within 12 months would be economically, technically, or operationally infeasible (*e.g.,* by reference to prohibitive costs, difficulty in securing required access rights and permits, long procurement lead times, and component/labor availability). Alternative valve shut-off measures must be in place within 7 days of a failed drill. For each RCV installed under §§ 195.258(c) or 195.418, the operator must conduct a point-to-point verification between SCADA displays, the installed valves, sensors, and communications equipment in accordance with § 195.446(c) and (e), or perform an equivalent verification.

Per this final rule, operators are required to identify corrective actions and lessons learned resulting from the validation and confirmation drills and share and implement them across its entire network of pipeline systems.

§ 195.452 Pipeline Integrity Management in High Consequence Areas

In this final rule, PHMSA is revising § 195.452(i)(4) to clarify the requirements for conducting emergency flow restricting device evaluations for HCAs, particularly when an operator installs such valves as preventive and mitigative measures to improve response times for, and mitigate the consequences of, pipeline ruptures. Emergency flow restriction devices that are installed in accordance with this section must meet all RMV requirements in part 195.

PHMSA is also requiring that risk analyses and assessments conducted under this section be completed prior to placing into service all onshore pipelines with diameters of 6 inches or greater and that are constructed or that have had 2 or more miles of pipeline replaced within 5 contiguous miles within a 24-month period after April 10, 2023. The implementation of emergency flow restricting device findings for any RMVs installed must meet § 195.418.

VI. Regulatory Analyses and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published pursuant to the authority granted to the Secretary of Transportation by the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*). Section 60102(a) authorizes issuance of regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. The final rule also implements a statutory mandate at 49 U.S.C. 60102(n) requiring the Secretary to issue regulations requiring the installation of RMVs or equivalent technology on new and entirely replaced transmission lines. *See also* 49 U.S.C. 5103 (regulatory authority to prescribe regulations for transportation of hazardous materials), and 30 U.S.C. 185(w)(3)) (authority to prescribe reporting requirements for pipelines traversing Federal lands). The Secretary delegated these authorities to the PHMSA Administrator in 49 CFR 1.97.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

Executive Order 12866 (''Regulatory Planning and Review'') [50] requires that ''agencies should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating. Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify.'' Further, Executive Order 12866 requires that ''agencies should maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach.'' Similarly, DOT Order 2100.6A (''Rulemaking and Guidance Procedures'') requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts.

This action has been determined to be significant under Executive Order 12866. The final rule has been reviewed by the Office of Management and Budget (OMB) in accordance with Executive Order 12866 and is consistent with the requirements of Executive Order 12866, 49 U.S.C. 60102(b)(5), and DOT Order 2100.6A. The Office of Information and Regulatory Affairs (OIRA) has not designated this rule as a ''major rule'' as defined by the Congressional Review Act (5 U.S.C. 801 *et seq.*).

Executive Order 12866 and DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which also reinforces requirements for notice and comment under the Administrative Procedure Act (5 U.S.C. 551 *et seq.*). Therefore, in the NPRM, PHMSA sought public comment on its proposed revisions to the Federal Pipeline Safety Regulations and the preliminary cost and benefit analyses in the Preliminary RIA, as well as any information that could assist in quantifying the costs and benefits of this rulemaking. Those comments are addressed in this final rule, and additional discussion about the costs and benefits of the final rule are provided within the RIA posted in the rulemaking docket.

The table below summarizes the annualized costs for the provisions in the final rule at a 3 percent and a 7 percent discount rate:

TABLE 1—ANNUALIZED COSTS OF THE FINAL RULE

[Millions 2019$]

System type	7% Discount rate	3% Discount rate
Natural gas	$2.5	$1.0
Hazardous liquid	3.4	1.5
Total	5.9	2.5

The benefits of the final rule consist of improved safety and avoided unquantified environmental harms (including, but not limited to, unquantified greenhouse gas emissions) from prompt identification, isolation, and mitigation actions with respect to unintentional or uncontrolled, large-volume releases of natural gas or hazardous liquids during a pipeline rupture. Benefits of the final rule will depend on the degree to which compliance actions result in additional safety measures, relative to the baseline, and the effectiveness of these measures in preventing or mitigating future pipeline releases or other incidents.

C. Executive Order 13132: Federalism

PHMSA analyzed this final rule in accordance with Executive Order 13132 (''Federalism'').[51] Executive Order 13132 requires agencies to assure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

The final rule does not have a substantial direct effect on the State and local governments, the relationship between the Federal government and the States, or the distribution of power and responsibilities among the various levels of government. This rulemaking action does not impose substantial direct compliance costs on State and local governments. Section 60104(c) of Title 49 of the United States Code prohibits certain State safety regulation of interstate pipelines. States can augment pipeline safety requirements for intrastate pipelines regulated by PHMSA, but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate. The preemptive effect of this final rule is limited to the minimum level necessary to achieve the objectives of the statutory authorities under which the final rule is promulgated. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the Administrative Procedure Act unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. This final rule was developed in accordance with Executive Order 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'') [52] to promote compliance with the Regulatory Flexibility Act and to ensure that the potential impacts of the rulemaking on small entities has been properly considered.

PHMSA prepared a FRFA, which is available in the docket for the rulemaking. In it, PHMSA certifies that the rule will not have a significant impact on a substantial number of small entities.

[50] 58 FR 51735 (Oct. 4, 1993).

[51] 64 FR 43255 (Aug. 10, 1999).

[52] 67 FR 53461 (Aug. 16, 2002).

E. National Environmental Policy Act

The National Environmental Policy Act (42 U.S.C. 4321 *et seq.;* NEPA) requires Federal agencies to consider the consequences of major Federal actions and prepare a detailed statement on actions significantly affecting the quality of the human environment. The Council on Environmental Quality implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (''Procedures for Considering Environmental Impacts'') establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

PHMSA has completed its NEPA analysis. Based on the final Environmental Assessment (EA), PHMSA determined that an environmental impact statement is not required for this rulemaking because it will not have a significant impact on the human environment. The final EA and Finding of No Significant Impact have been placed into the docket and address comments received on an earlier draft EA.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this final rule per the principles and criteria in Executive Order 13175 (''Consultation and Coordination With Indian Tribal Governments'') [53] and DOT Order 5301.1 (''Department of Transportation Policies, Programs, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). Executive Order 13175 requires agencies to assure meaningful and timely input from Tribal Government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities or the relationship and distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the rulemaking and determined that it would not significantly or uniquely affect Tribal communities or Tribal governments. The rulemaking's regulatory amendments are facially neutral and would have broad, national scope; PHMSA, therefore, does not expect this rulemaking to significantly or uniquely affect Tribal communities, much less impose substantial compliance costs on Native American Tribal governments or mandate Tribal action. And insofar as PHMSA expects the rulemaking will improve pipeline safety and reduce environmental risks, PHMSA does not expect it would entail disproportionately high adverse risks for Tribal communities. PHMSA also received no comments alleging ''substantial direct compliance costs'' or ''substantial direct effects'' on Tribal communities and Governments. For these reasons, PHMSA has determined the funding and consultation requirements of Executive Order 13175 and DOT Order 5301.1 do not apply.

G. Executive Order 13211

Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'') [54] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' Executive Order 13211 defines a ''significant energy action'' as any action by an agency (normally published in the **Federal Register**) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation that (1) (i) is a significant regulatory action under Executive Order 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy (including a shortfall in supply, price increases, and increased use of foreign supplies); or (2) is designated by the Administrator of the OIRA as a significant energy action.

This final rule is a significant action under Executive Order 12866; however, it is expected to have an annual effect on the economy of less than $100 million. Further, this action is not likely to have a significant adverse effect on the supply, distribution, or use of energy in the United States. The Administrator of OIRA has not designated the final rule as a significant energy action. For additional discussion of the anticipated economic impact of this rulemaking, please review the RIA posted in the rulemaking docket.

H. Paperwork Reduction Act

Under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), no person is required to respond to an information collection unless it has been approved by OMB and displays a valid OMB control number. Pursuant to implementing regulations at 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests.

PHMSA published an NPRM seeking public comment on its proposed revisions to the Federal Pipeline Safety Regulations finalized in this rulemaking. Based on comments received and the updated provisions contained within this final rule, PHMSA is expanding the notification and recordkeeping requirements for gas and hazardous liquid pipeline operators. The provisions in this final rule include the following Paperwork Reduction Act impacts:

Operators are required to document certain procedures and to maintain records pertaining to various aspects of their RMV and alternative equivalent technology operations. Operators who have experienced a rupture or RMV shut-off are required to complete a post-incident or -accident analysis. The summary of this analysis, all documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline.

Operators must also develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture is an actual rupture event or non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture.

The final rule (at 49 CFR 192.179 and 49 CFR 195.258) requires operators who elect to use alternative equivalent technology to notify PHMSA's Office of Pipeline Safety at least 90 days in advance of use. An operator choosing this option must submit a technical and safety evaluation (including design, construction, and operating procedures) for the alternative equivalent technology to the Associate Administrator of Pipeline Safety with the notification. PHMSA would then have 90 days to object to the alternative equivalent technology via letter from the Associate Administrator of Pipeline Safety; otherwise, the alternative equivalent technology would be acceptable for use. Operators who wish to use a manual valve as an alternative equivalent technology will also be required to include within their notification to PHMSA an explanation that installation of an RMV would be economically, technically, or operationally infeasible.

An operator may seek PHMSA's approval for an exemption from several other regulatory installation and

[53] 65 FR 67249 (Nov. 6, 2000).

[54] 66 FR 28355 (May 18, 2001).

operational requirements under the final rule by notifying PHMSA in certain instances. For example, an operator of a gas pipeline may plan to leave an RMV open for more than 30 minutes following rupture identification if the operator demonstrates to PHMSA, in accordance with the notification procedures in § 192.18, that closing an RMV, or alternative equivalent technology would be detrimental to public safety. Likewise, for hazardous liquid pipeline segments not in an HCA and which could not affect an HCA, an operator may request exemption from specified requirements if it can demonstrate to PHMSA, in accordance with the notification procedures in § 195.18, that installing an otherwise-required RMV, or alternative equivalent technology, would be economically, technically, or operationally infeasible. Similarly, the maximum valve spacing for HVL pipelines can be increased by 1.25 times the distance to a maximum of 9 ⅜ miles if the operator submits a notification for PHMSA review demonstrating that the installation of a valve at the otherwise-required spacing is economically, technically, or operationally infeasible. Lastly, the final rule also identifies procedures for operators of gas and hazardous liquid lines to submit for PHMSA review a notification requesting extension of required timelines (*e.g.,* for RMV or alternative equivalent technology installation, RMV operability post-installation) specified in the final rule.

PHMSA proposes to create an information collection under OMB Control Number 2137–0637 titled, ''Rupture Mitigation Valve Recordkeeping Requirements'' to account for the expanded recordkeeping requirements in this final rule. PHMSA also proposes to create an information collection under OMB Control Number 2137–0638 titled, ''Rupture Mitigation Valve Notification Requirements'' to account for the expanded notification requirements in this final rule.

PHMSA will request approval of these information collections from the Office of Management and Budget (OMB) based on the requirements that trigger components of the Paperwork Reduction Act and will notify the public through a separate notice published in the **Federal Register** upon OMB approval of the information collection requirements.

The following information is provided for each of these information collections: (1) Title of the information collection; (2) OMB control number; (3) current expiration date; (4) type of request; (5) abstract of the information collection activity; (6) description of affected public; (7) estimate of total annual reporting and recordkeeping burden; and (8) frequency of collection. The information collection burdens are estimated as follows:

1. Title: ''Rupture Mitigation Valve Recordkeeping Requirements.''

OMB Control Number: 2137–0637.

Current Expiration Date: To be determined by OMB.

Abstract: The ''Amendments to parts 192 and 195 to Require Valve Installation and Minimum Rupture Detection Standards Final Rule'' requires operators of gas and hazardous liquid pipelines to document certain procedures and to maintain records pertaining to various aspects of their RMV and alternative equivalent technology operations. Operators who have experienced a rupture or RMV valve shut-off are required to complete a post-incident review. The post-incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the life of the pipeline. PHMSA estimates that it will take operators, on average, 40 hours to comply with this requirement.

Operators must also develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture is an actual rupture event or non-rupture event as soon as practicable. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture. PHMSA estimates that it will take operators 40 hours to comply with this requirement. Operators are also required to maintain certain records if they experience certain circumstances involving their RMV operations. On average, PHMSA expects that it will take operators 8 hours to complete these recordkeeping requirements.

PHMSA estimates that 1,812 operators (1,304 natural gas and 508 hazardous liquid operators) will be potentially impacted by these requirements. At minimum, all 1,812 operators will be required to develop written rupture identification procedures. PHMSA estimates 46 of these operators will experience a rupture that will require the completion of a post-incident or -accident summary. PHMSA expects that 10 percent of the affected community will be subject to the various other recordkeeping requirements. As a result, PHMSA expects this information collection to result in 4,213 responses and 85,724 burden hours annually.

Affected Public: Operators of PHMSA-Regulated Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 4,213.

Total Annual Burden Hours: 85,724.

Frequency of Collection: On occasion.

2. Title: ''Rupture Mitigation Valve Notification Requirements.''

OMB Control Number: 2137–0638.

Current Expiration Date: To be determined by OMB.

Abstract: The ''Amendments to Parts 192 and 195 to Require Valve Installation and Minimum Rupture Detection Standards Final Rule'' requires operators to notify PHMSA in certain instances regarding installation and operation of RMVs and alternative equivalent technologies. 49 CFR 192.179 and 195.258 require operators who elect to use alternative equivalent technology to notify the Office of Pipeline Safety at least 90 days in advance of use. An operator choosing this option must include a technical and safety evaluation, including design, construction, and operating procedures for the alternative equivalent technology with the notification. Operators who wish to use a manual valve as an alternative equivalent technology will also be required to include within their notification to PHMSA an explanation that installation of an RMV would be economically, technically, or operationally infeasible. PHMSA expects most operators to use standard technology and, as such, estimates this notification requirement will result in approximately four responses annually. PHMSA estimates each operator will spend 40 hours annually compiling the necessary components of this notification requirement.

Operators must notify PHMSA if an RMV cannot be made operational within 14 days of installation. Operators must also notify PHMSA if a valve cannot be repaired or replaced within 12 months. PHMSA expects roughly 10 percent of operators to experience these circumstances taking 2 hours to complete the notification requirement.

An operator may seek exemption from certain regulatory requirements by notifying PHMSA in certain instances. For example, an operator may plan to leave an RMV open for more than 30 minutes following rupture identification if the operator demonstrates to PHMSA, that closing an RMV, or alternative equivalent technology, would be detrimental to public safety.

Likewise, for hazardous liquid pipeline segments not in an HCA which could not affect an HCA, an operator may request exemption from certain requirements if it can demonstrate to

PHMSA that installing an otherwise-required RMV, or alternative equivalent technology, would be economically, technically, or operationally infeasible. PHMSA expects 10 percent of operators to make each of these and other notifications annually. PHMSA estimates that it will take operators, on average, 8 hours to make these notifications.

Affected Public: Operators of PHMSA-Regulated Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 598.

Total Annual Burden Hours: 2,378.

Frequency of Collection: On occasion.

Questions regarding these information collections should be directed to Angela Hill, Office of Pipeline Safety (PHP–30), Pipeline and Hazardous Materials Safety Administration, 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001. Telephone: 202–366–1246.

I. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector of $100 million or more (adjusted annually for inflation) in any given year, the agency must prepare, among other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate.

As explained in the RIA, PHMSA determined that this final rule does not impose enforceable duties on State, local, or Tribal governments or on the private sector of $100 million or more (adjusted annually for inflation) in any one year. A copy of the RIA is available for review in the docket. Therefore, the Department has determined that no assessment is required pursuant to UMRA.

J. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement [55] at *http://www.dot.gov/privacy.*

K. Regulation Identifier Number

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN number contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

L. Executive Order 13609 and International Trade Analysis

Executive Order 13609 (''Promoting International Regulatory Cooperation'') [56] requires agencies consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards, so long as the standards have a legitimate domestic objective, such as providing for safety, and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards.

PHMSA participates in the establishment of international standards to protect the safety of the American public. PHMSA has assessed the effects of the rulemaking and determined that it will not cause unnecessary obstacles to foreign trade.

M. Environmental Justice

DOT Order 5610.2(b) and Executive Orders 12898 (''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations''),[57] 13985 (''Advancing Racial Equity and Support for Underserved Communities Through the Federal Government''),[58] 13990, and 14008 require DOT operational administrations to achieve environmental justice as part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects, including interrelated social and economic effects, of their programs, policies, and activities on minority populations, low-income populations, and other underserved disadvantaged communities.

PHMSA has evaluated this final rule under DOT Order 5610.2(b) and the Executive Orders listed above and determined it will not cause disproportionately high and adverse human health and environmental effects on minority populations, low-income populations, or other underserved and disadvantaged communities. The rulemaking is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor is it expected to adversely impact any particular population, region, or community. And insofar as PHMSA expects the rulemaking would reduce the safety and environmental risks associated with affected natural gas and hazardous liquid pipelines, many of which are sited in the vicinity of environmental justice communities,[59] PHMSA does not expect the regulatory amendments introduced by this final rule would entail disproportionately high adverse risks for minority populations, low-income populations, or other underserved and other disadvantaged communities in the vicinity of those pipelines. Lastly, as explained in final EA, PHMSA expects that the regulatory amendments in this final rule will yield GHG emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority, low-income, underserved, and other disadvantaged populations and communities.

List of Subjects

49 CFR Part 192

Gas, Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

[55] 65 FR 19476 (Apr. 11, 2000).

[56] 77 FR 26413 (May 4, 2012).

[57] 59 FR 7629 (Feb. 16, 1994).

[58] 86 FR 7009 (Jan. 20, 2021).

[59] *See* Ryan Emmanuel, et al., ''Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,'' 5:6 GeoHealth (June 2021), *https://agupubs.onlinelibrary.wiley.com/toc/24711403/2021/5/6* (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

49 CFR Part 195

Anhydrous ammonia, Carbon dioxide, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, PHMSA amends 49 CFR parts 192 and 195 as follows:

PART 192—TRANSPORTATION OF NATURAL GAS AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 1. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. In § 192.3, definitions for ''entirely replaced onshore transmission pipeline segments'', ''notification of potential rupture'', and ''rupture-mitigation valve'' are added in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Entirely replaced onshore transmission pipeline segments means, for the purposes of §§ 192.179 and 192.634, where 2 or more miles, in the aggregate, of onshore transmission pipeline have been replaced within any 5 contiguous miles of pipeline within any 24-month period.

* * * * *

Notification of potential rupture means the notification to, or observation by, an operator of indicia identified in § 192.635 of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline.

* * * * *

Rupture-mitigation valve (RMV) means an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture.

* * * * *

■ 3. In § 192.9, paragraphs (d)(1) and (e)(1)(i) are revised to read as follows:

§ 192.9 What requirements apply to gathering lines?

* * * * *

(d) * * *

(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. Compliance with §§ 192.67, 192.127, 192.179(e), 192.179(f), 192.205, 192.227(c), 192.285(e), 192.506, 192.634, and 192.636 is not required.

* * * * *

(e) * * *

(1) * * *

(i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B though G and J of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e), 192.179(f), 192.205, 192.227(c), 192.285(e), 192.506, 192.634, and 192.636 is not required;

* * * * *

■ 4. In § 192.18, paragraph (c) is revised to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, § 192.9, § 192.179, § 192.506, § 192.607, § 192.619, § 192.624, § 192.632, § 192.634, § 192.636, § 192.710, § 192.712, § 192.745, § 192.921, or § 192.937, a notification for use of a different integrity assessment method, analytical method, sampling approach, or technique (*e.g.,* ''other technology'' or ''alternative equivalent technology'') than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposal, or that PHMSA requires additional time and/or more information to conduct its review.

■ 5. In § 192.179, paragraphs (e) through (h) are added to read as follows:

§ 192.179 Transmission line valves.

* * * * *

(e) For onshore transmission pipeline segments with diameters greater than or equal to 6 inches that are constructed after April 10, 2023, the operator must install rupture-mitigation valves (RMV) or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (g) of this section. All RMVs and alternative equivalent technologies installed pursuant to this paragraph must meet the requirements of §§ 192.634 and 192.636. Exempted from this paragraph's installation requirements are pipeline segments in Class 1, or Class 2 locations that have a potential impact radius (PIR), as defined in § 192.903, of 150 feet or less. An operator may request an extension of the installation compliance deadline requirements of this paragraph (e) if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular new pipeline.

(f) For entirely replaced onshore transmission pipeline segments, as defined in § 192.3, with diameters greater than or equal to 6 inches and that are installed after April 10, 2023, the operator must install RMVs or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (g) of this section. All RMVs and alternative equivalent technologies installed pursuant to this paragraph must meet the requirements of §§ 192.634 and 192.636. The requirements of this paragraph apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. This paragraph's installation requirements do not apply to pipe segments in Class 1 or Class 2 locations that have a PIR, as defined in § 192.903, that is less than or equal to 150 feet. An operator may request an extension of the installation compliance deadline requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular pipeline replacement project.

(g) If an operator elects to use alternative equivalent technology in accordance with paragraph (e) or (f) of this section, the operator must notify PHMSA in accordance with the procedures in § 192.18. The operator must include a technical and safety evaluation in its notice to PHMSA. Valves that are installed as alternative equivalent technology must comply with §§ 192.634 and 192.636. An operator requesting use of manual valves as an alternative equivalent technology must also include within the notification submitted to PHMSA a demonstration that installation of an RMV as otherwise required would be economically, technically, or operationally infeasible. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, and use of such valve would not require a notification to PHMSA in accordance with § 192.18, but it must comply with § 192.636.

(h) The valve spacing requirements of paragraph (a) of this section do not apply to pipe replacements on a pipeline if the distance between each point on the pipeline and the nearest valve does not exceed:

(1) Four (4) miles in Class 4 locations, with a total spacing between valves no greater than 8 miles;

(2) Seven-and-a-half (7½) miles in Class 3 locations, with a total spacing between valves no greater than 15 miles; or

(3) Ten (10) miles in Class 1 or 2 locations, with a total spacing between valves no greater than 20 miles.

■ 6. Section 192.610 is added to read as follows:

§ 192.610 Change in class location: Change in valve spacing.

(a) If a class location change on a transmission pipeline occurs after October 5, 2022, and results in pipe replacement, of 2 or more miles, in the aggregate, within any 5 contiguous miles within a 24-month period, to meet the maximum allowable operating pressure (MAOP) requirements in § 192.611, § 192.619, or § 192.620, then the requirements in §§ 192.179, 192.634, and 192.636, as applicable, apply to the new class location, and the operator must install valves, including rupture-mitigation valves (RMV) or alternative equivalent technologies, as necessary, to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with the timing requirement in § 192.611(d) for compliance after a class location change.

(b) If a class location change occurs after October 5, 2022, and results in pipe replacement of less than 2 miles within 5 contiguous miles during a 24-month period, to meet the MAOP requirements in § 192.611, § 192.619, or § 192.620, then within 24 months of the class location change, in accordance with § 192.611(d), the operator must either:

(1) Comply with the valve spacing requirements of § 192.179(a) for the replaced pipeline segment; or

(2) Install or use existing RMVs or alternative equivalent technologies so that the entirety of the replaced pipeline segments are between at least two RMVs or alternative equivalent technologies. The distance between RMVs and alternative equivalent technologies for the replaced segment must not exceed 20 miles. The RMVs and alternative equivalent technologies must comply with the applicable requirements of § 192.636.

(c) The provisions of paragraph (b) of this section do not apply to pipeline replacements that amount to less than 1,000 feet within any one contiguous mile during any 24-month period.

■ 7. In § 192.615, paragraphs (a)(2), (6), (8), and (11) are revised, paragraph (a)(12) is added, and paragraph (c) introductory text is revised to read as follows:

§ 192.615 Emergency plans.

(a) * * *

(2) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (*i.e.,* 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, and fire, police, and other public officials. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9–1–1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. An operator must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone number(s) for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies.

* * * * *

(6) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released gas to life, property, or the environment.

* * * * *

(8) Notifying the appropriate public safety answering point (*i.e.,* 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, and fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving a notification of potential rupture, as defined in § 192.3, to coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of § 192.179, § 192.634, or § 192.636.

* * * * *

(11) Actions required to be taken by a controller during an emergency in accordance with the operator's emergency plans and requirements set forth in §§ 192.631, 192.634, and 192.636.

(12) Each operator must develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in § 192.3, is an actual rupture event or a non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture and identify an actual rupture. For operators installing valves in accordance with § 192.179(e), § 192.179(f), or that are subject to the requirements in § 192.634, those procedures must provide for rupture identification as soon as practicable.

* * * * *

(c) Each operator must establish and maintain liaison with the appropriate public safety answering point (*i.e.,* 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, to:

* * * * *

■ 8. Section 192.617 is revised to read as follows:

§ 192.617 Investigation of failures and incidents.

(a) *Post-failure and incident procedures.* Each operator must establish and follow procedures for investigating and analyzing failures and incidents as defined in § 191.3, including sending the failed pipe, component, or equipment for laboratory testing or examination, where appropriate, for the purpose of determining the causes and contributing factor(s) of the failure or incident and minimizing the possibility of a recurrence.

(b) *Post-failure and incident lessons learned.* Each operator must develop, implement, and incorporate lessons learned from a post-failure or incident review into its written procedures, including personnel training and qualification programs, and design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

(c) *Analysis of rupture and valve shut-offs.* If an incident on an onshore gas transmission pipeline or a Type A gathering pipeline involves the closure of a rupture-mitigation valve (RMV), as defined in § 192.3, or the closure of alternative equivalent technology, the operator of the pipeline must also conduct a post-incident analysis of all of the factors that may have impacted the release volume and the consequences of the incident and identify and implement operations and maintenance measures to prevent or minimize the consequences of a future incident. The requirements of this paragraph (c) are not applicable to distribution pipelines or Types B and C gas gathering pipelines. The analysis must include all relevant factors impacting the release volume and consequences, 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 incident;

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

(3) Actual response time from identifying a rupture following a notification of potential rupture, as defined at § 192.3, to initiation of mitigative actions and isolation of the pipeline segment, and the appropriateness and effectiveness of the mitigative actions taken;

(4) Location and timeliness of actuation of RMVs or alternative equivalent technologies; and

(5) All other factors the operator deems appropriate.

(d) *Rupture post-failure and incident summary.* If a failure or incident on an onshore gas transmission pipeline or a Type A gathering pipeline involves the identification of a rupture following a notification of potential rupture, or the closure of an RMV (as those terms are defined in § 192.3), or the closure of an alternative equivalent technology, the operator of the pipeline must complete a summary of the post-failure or incident review required by paragraph (c) of this section within 90 days of the incident, and while the investigation is pending, conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. The final post-failure or incident summary, and all other reviews and analyses produced under the requirements of this section, must be reviewed, dated, and signed by the operator's appropriate senior executive officer. The final post-failure or incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline. The requirements of this paragraph (d) are not applicable to distribution pipelines or Types B and C gas gathering pipelines.

■ 9. Section 192.634 is added to read as follows:

§ 192.634 Transmission lines: Onshore valve shut-off for rupture mitigation.

(a) *Applicability.* For new or entirely replaced onshore transmission pipeline segments with diameters of 6 inches or greater that are located in high-consequence areas (HCA) or Class 3 or Class 4 locations and that are installed after April 10, 2023, an operator must install or use existing rupture-mitigation valves (RMV), or an alternative equivalent technology, according to the requirements of this section and §§ 192.179 and 192.636. RMVs and alternative equivalent technologies must be operational within 14 days of placing the new or replaced pipeline segment into service. An operator may request an extension of this 14-day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this section apply to all applicable pipe replacement projects, even those that do not otherwise involve the addition or replacement of a valve. This section does not apply to pipe segments in Class 1 or Class 2 locations that have a potential impact radius (PIR), as defined in § 192.903, that is less than or equal to 150 feet.

(b) *Maximum spacing between valves.* RMVs, or alternative equivalent technology, must be installed in accordance with the following requirements:

(1) *Shut-off segment.* For purposes of this section, a "shut-off segment" means the segment of pipe located between the upstream valve closest to the upstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment and the downstream valve closest to the downstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment so that the entirety of the segment that is within the HCA or the Class 3 or Class 4 location is between at least two RMVs or alternative equivalent technologies. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream valves, the shut-off segment also must extend to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or Class 4 locations or HCA segments may be contained within a single shut-off segment. The operator is not required to select the closest valve to the shut-off segment as the RMV, as that term is defined in § 192.3, or the alternative equivalent technology. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, but it must be able to be closed within 30 minutes following rupture identification, as that term is defined at § 192.3. Such a valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with § 192.18.

(2) *Shut-off segment valve spacing.* A pipeline subject to paragraph (a) of this section must have RMVs or alternative equivalent technology on the upstream and downstream side of the pipeline segment. The distance between RMVs or alternative equivalent technologies must not exceed:

(i) Eight (8) miles for any Class 4 location,

(ii) Fifteen (15) miles for any Class 3 location, or

(iii) Twenty (20) miles for all other locations.

(3) *Laterals.* Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of the laterals contributing gas volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment gas volume based upon maximum flow volume at the operating pressure. For laterals that are 12 inches in diameter or less, a check valve that allows gas to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction may be used as an alternative equivalent technology where it is

positioned to stop flow into the shut-off segment. Such check valves that are used as an alternative equivalent technology in accordance with this paragraph are not subject to § 192.636, but they must be inspected, operated, and remediated in accordance with § 192.745, including for closure and leakage to ensure operational reliability. An operator using such a check valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 192.18 and 192.179 develop and implement maintenance procedures for such equipment that meet § 192.745.

(4) *Crossovers.* An operator may use a manual valve as an alternative equivalent technology in lieu of an RMV for a crossover connection if, during normal operations, the valve is closed to prevent the flow of gas by the use of a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must develop and implement operating procedures and document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of gas. An operator using such a manual valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 192.18 and 192.179.

(c) *Manual operation upon identification of a rupture.* Operators using a manual valve as an alternative equivalent technology as authorized pursuant to §§ 192.18 and 192.179 must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shut-off in accordance with this section and § 192.636. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to shut off all valves manually, not to exceed the maximum response time allowed under § 192.636(b).

■ 10. Section 192.635 is added to read as follows:

§ 192.635 Notification of potential rupture.

(a) As used in this part, a ''notification of potential rupture'' refers to the notification of, or observation by, an operator (*e.g.,* by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline:

(1) An unanticipated or unexplained pressure loss outside of the pipeline's normal operating pressures, as defined in the operator's written procedures. The operator must establish in its written procedures that an unanticipated or unplanned pressure loss is outside of the pipeline's normal operating pressures when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less, unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in gas demand, gas receipts, or gas deliveries; or

(2) An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting paragraph (a)(1) of this section; or

(3) Any unanticipated or unexplained rapid release of a large volume of gas, a fire, or an explosion in the immediate vicinity of the pipeline.

(b) A notification of potential rupture occurs when an operator first receives notice of or observes an event specified in paragraph (a) of this section.

■ 11. Section 192.636 is added to read as follows:

§ 192.636 Transmission lines: Response to a rupture; capabilities of rupture-mitigation valves (RMVs) or alternative equivalent technologies.

(a) *Scope.* The requirements in this section apply to rupture-mitigation valves (RMVs), as defined in § 192.3, or alternative equivalent technologies, installed pursuant to §§ 192.179(e), (f), and (g) and 192.634.

(b) *Rupture identification and valve shut-off time.* An operator must, as soon as practicable but within 30 minutes of rupture identification (*see* § 192.615(a)(12)), fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of gas released from a pipeline and mitigate the consequences of a rupture.

(c) *Open valves.* An operator may leave an RMV or alternative equivalent technology open for more than 30 minutes, as required by paragraph (b) of this section, if the operator has previously established in its operating procedures and demonstrated within a notice submitted under § 192.18 for PHMSA review, that closing the RMV or alternative equivalent technology would be detrimental to public safety. The request must have been coordinated with appropriate local emergency responders, and the operator and emergency responders must determine that it is safe to leave the valve open. Operators must have written procedures for determining whether to leave an RMV or alternative equivalent technology open, including plans to communicate with local emergency responders and minimize environmental impacts, which must be submitted as part of its notification to PHMSA.

(d) *Valve monitoring and operation capabilities.* An RMV, as defined in § 192.3, or alternative equivalent technology, must be capable of being monitored or controlled either remotely or by on-site personnel as follows:

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

(2) Monitored for valve status (*i.e.,* open, closed, or partial closed/open), upstream pressure, and downstream pressure. For automatic shut-off valves (ASV), an operator does not need to monitor remotely a valve's status if the operator has the capability to monitor pressures or gas flow rate within each pipeline segment located between RMVs or alternative equivalent technologies to identify and locate a rupture. Pipeline segments that use manual valves or other alternative equivalent technologies must have the capability to monitor pressures or gas flow rates on the pipeline to identify and locate a rupture; and

(3) Have a back-up power source to maintain SCADA systems or other remote communications for remote-control valve (RCV) or automatic shut-off valve (ASV) operational status, or be monitored and controlled by on-site personnel.

(e) *Monitoring of valve shut-off response status.* The position and operational status of an RMV must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means. An operator does not need to monitor remotely an ASV's status if the operator has the capability to monitor pressures or gas flow rate on the pipeline to identify and locate a rupture.

(f) *Flow modeling for automatic shut-off valves.* Prior to using an ASV as an RMV, an operator must conduct flow modeling for the shut-off segment and any laterals that feed the shut-off segment, so that the valve will close within 30 minutes or less following rupture identification, consistent with the operator's procedures, and in accordance with § 192.3 and this section. The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions that may be encountered during the year, not exceeding a period of 15 months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or gas receipt tie-ins. If operating conditions change that could affect the ASV set pressures and the 30-minute valve closure time after notification of potential rupture, as defined at § 192.3, an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with § 192.745. The flow model must include a time/pressure chart for the segment containing the ASV if a rupture occurs. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could render the 30-minute valve closure time unachievable.

(g) *Manual valves in non-HCA, Class 1 locations.* For pipeline segments in a Class 1 location that do not meet the definition of a high consequence area (HCA), an operator submitting a notification pursuant to §§ 192.18 and 192.179 for use of manual valves as an alternative equivalent technology may also request an exemption from the requirements of § 192.636(b).

■ 12. In § 192.745, paragraphs (c) through (f) are added to read as follows:

§ 192.745 Valve maintenance: Transmission lines.

* * * * *

(c) For each remote-control valve (RCV) installed in accordance with § 192.179 or § 192.634, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with § 192.631(c) and (e).

(d) For each alternative equivalent technology installed on an onshore pipeline under § 192.179(e) or (f) or § 192.634 that is manually or locally operated (*i.e.,* not a rupture-mitigation valve (RMV), as that term is defined in § 192.3):

(1) Operators must achieve a valve closure time of 30 minutes or less, pursuant to § 192.636(b), through an initial drill and through periodic validation as required in paragraph (d)(2) of this section. An operator must review and document the results of each phase of the drill response to validate the total response time, including confirming the rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification.

(2) Within each pipeline system and within each operating or maintenance field work unit, operators must randomly select a valve serving as an alternative equivalent technology in lieu of an RMV for an annual 30-minute-total response time validation drill that simulates worst-case conditions for that location to ensure compliance with § 192.636. Operators are not required to close the valve fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance with drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar year, with intervals not to exceed 15 months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph.

(3) If the 30-minute-maximum response time cannot be achieved during the drill, the operator must revise response efforts to achieve compliance with § 192.636 as soon as practicable but no later than 12 months after the drill. Alternative valve shut-off measures must be in place in accordance with paragraph (e) of this section within 7 days of a failed drill.

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

(i) Training and qualifications programs;

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

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

(5) The requirements of this paragraph (d) do not apply to manual valves who, pursuant to § 192.636(g), have been exempted from the requirements of § 192.636(b).

(e) Each operator must develop and implement remedial measures to correct any valve installed on an onshore pipeline under § 192.179(e) or (f) or § 192.634 that is indicated to be inoperable or unable to maintain effective shut-off as follows:

(1) Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain effective shut-off. An operator must request an extension from PHMSA in accordance with § 192.18 if repair or replacement of a valve within 12 months would be economically, technically, or operationally infeasible; and

(2) Designate an alternative valve acting as an RMV within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Such valves are not required to comply with the valve spacing requirements of this part.

(f) An operator using an ASV as an RMV, in accordance with §§ 192.3, 192.179, 192.634, and 192.636, must document and confirm the ASV shut-in pressures, in accordance with § 192.636(f), on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required, on a calendar year basis not to exceed 15 months.

■ 13. In § 192.935, paragraph (c) is revised and paragraph (f) is added to read as follows:

§ 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 (RMV) or alternative equivalent technology would be an efficient means of adding protection to a high-consequence area (HCA) in the event of a gas release, an operator must install the RMV or alternative equivalent technology. In making that determination, an operator must, at least, evaluate the following factors—timing 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. An RMV or alternative equivalent technology installed under this paragraph must meet all of the other applicable requirements in this part.

* * * * *

(f) *Periodic evaluations.* Risk analyses and assessments conducted under paragraph (c) of this section must be reviewed by the operator and certified by a senior executive of the company, for operational matters that could affect rupture-mitigation processes and procedures. Review and certification must occur once per calendar year, with the period between reviews not to exceed 15 months, and must also occur within 3 months of an incident or safety-related condition, as those terms are defined at §§ 191.3 and 191.23, respectively.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 14. The authority citation for part 195 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et. seq.,* and 49 CFR 1.97.

■ 15. In § 195.2, definitions for ''entirely replaced onshore hazardous liquid or carbon dioxide line segments'', ''notification of potential rupture'', and ''rupture-mitigation valve'' are added in alphabetical order to read as follows:

§ 195.2 Definitions.

* * * * *

Entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments, for the purposes of §§ 195.258, 195.260, and 195.418, means where 2 or more miles of pipe, in the aggregate, have been replaced within any 5 contiguous miles within any 24-month period.

* * * * *

Notification of Potential Rupture means the notification to, or observation by, an operator of indicia identified in § 195.417 of a potential unintentional or uncontrolled release of a large volume of commodity from a pipeline.

* * * * *

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

* * * * *

■ 16. In § 195.11, paragraph (b)(2) is revised to read as follows:

§ 195.11 What is a regulated rural gathering line and what requirements apply?

* * * * *

(b) * * *

(2) For steel pipelines contracted, replaced, relocated, or otherwise changed after July 3, 2009:

(i) Design, install, construct, initially inspect, and initially test the pipeline in compliance with this part, unless the pipeline is converted under § 195.5.

(ii) Except for pipelines subject to § 195.260(e), such pipelines are not subject to the rupture-mitigation valve (RMV) and alternative equivalent technology requirements in §§ 195.258(c) and (d), 195.418, and 195.419.

* * * * *

■ 17. Section 195.18 is added to read as follows:

§ 195.18 How to notify PHMSA.

(a) An operator must provide any notification required by this part by:

(1) Sending the notification by electronic mail to *InformationResourcesManager@dot.gov;* or

(2) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, 1200 New Jersey Ave. SE, Washington, DC 20590.

(b) An operator must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate pipeline segment is regulated by that State.

(c) Unless otherwise specified, if an operator submits, pursuant to § 195.258, § 195.260, § 195.418, § 195.419, § 195.420 or § 195.452 a notification requesting use of a different integrity assessment method, analytical method, sampling approach, compliance timeline, or technique (*e.g.,* ''other technology'' or ''alternative equivalent technology'') than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using that other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submittal of the notification unless it receives a letter from the Associate Administrator of Pipeline Safety informing the operator that PHMSA objects to the proposal, or that PHMSA requires additional time and/or information to conduct its review.

■ 18. In § 195.258, paragraphs (c) through (e) are added to read as follows:

§ 195.258 Valves: General.

* * * * *

(c) For all onshore hazardous liquid or carbon dioxide pipeline segments with diameters greater than or equal to 6 inches that are constructed after April 10, 2023, the operator must install rupture-mitigation valves (RMV) or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section and § 195.260. An operator using alternative equivalent technology must notify PHMSA in accordance with the procedure in paragraph (e) of this section. All RMVs and alternative equivalent technology installed as required by this section must meet the requirements of § 195.419. An operator may request an extension of the installation compliance deadline requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in § 195.18, that those installation deadline requirements would be economically, technically, or operationally infeasible for a particular new pipeline.

(d) For all entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments with diameters greater than or equal to 6 inches that have been replaced after April 10, 2023, the operator must install RMVs or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator using alternative equivalent technology must notify PHMSA in accordance with the procedure in paragraph (e) of this section. All valves installed as required by this section must meet the requirements of § 195.419. The requirements of this paragraph (d) apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. An operator may request an extension of the installation compliance deadline requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in § 195.18, that those installation deadline requirements would be economically, technically, or operationally infeasible for a particular pipeline replacement project.

(e) If an operator elects to use alternative equivalent technology in accordance with paragraph (c) or (d) of this section, the operator must notify PHMSA in accordance with § 195.18. The operator must include a technical and safety evaluation in its notice to PHMSA. Valves that are installed as alternative equivalent technology must comply with §§ 195.418, 195.419, and 195.420. An operator requesting use of manual valves as an alternative equivalent technology must also include within the notification submitted to PHMSA a demonstration that installation of an RMV as otherwise required would be economically, technically, or operationally infeasible. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology. Such a valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with § 195.18, but it must comply with §§ 195.419 and 195.420.

■ 19. Section 195.260 is revised to read as follows:

§ 195.260 Valves: Location.

A valve must be installed at each of the following locations:

(a) On the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency.

(b) On each pipeline entering or leaving a breakout storage tank area in a manner that permits isolation of the tank from other facilities.

(c) On each pipeline at locations 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 (HCA). For newly constructed or entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments, as that term is defined at § 195.2, that are installed after April 10, 2023, valve spacing must not exceed 15 miles for pipeline segments that could affect or are in HCAs, as defined in § 195.450, and 20 miles for pipeline segments that could not affect HCAs. Valves on pipeline segments that are located in HCAs or which could affect HCAs must be installed at locations as determined by the operator's process for identifying preventive and mitigative measures established pursuant to § 195.452(i) and by using the selection process in section I.B of appendix C of part 195, but with a maximum distance that does not exceed 7½ miles from the endpoints of the HCA segment or the segment that could affect an HCA. An operator may request an exemption from the compliance deadline requirements of this section for valve installation at the specified valve spacing if it can demonstrate to PHMSA, in accordance with the notification procedures in § 195.18, that those compliance deadline requirements would be economically, technically, or operationally infeasible.

(d) On each lateral takeoff from a pipeline in a manner that permits shutting off the lateral without interrupting flow in the pipeline.

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

(1) Valves must be installed at locations outside of the 100-year flood plain or be equipped with actuators or other control equipment that is installed so as not to be impacted by flood conditions; and

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

(f) On each side of a reservoir holding water for human consumption.

(g) On each highly volatile liquid (HVL) pipeline that is located in a high-population area or other populated area, as defined in § 195.450, and that is constructed, or where 2 or more miles of pipe have been replaced within any 5 contiguous miles within any 24-month period, after April 10, 2023, with a maximum valve spacing of 7½ miles. The maximum valve spacing intervals may be increased by 1.25 times the distance up to a 9 ⅜-mile spacing, provided the operator:

(1) Submits for PHMSA review a notification pursuant to § 195.18 requesting alternative spacing because installation of a valve at a particular location between a 7-mile to a 7½-mile spacing would be economically, technically, or operationally infeasible, and that an alternative spacing would not adversely impact safety; and

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

(h) An operator may submit for PHMSA review, in accordance with § 195.18, a notification requesting site-specific exemption from the valve installation requirements or valve spacing requirements of paragraph (c), (e), or (f) of this section and demonstrating such exemption would not adversely affect safety. An operator may also submit for PHMSA review, in accordance with § 195.18, a notification requesting an extension of the compliance deadline requirements for valve installation and spacing of this section because those compliance deadline requirements would be economically, technically, or operationally infeasible for a particular new construction or pipeline replacement project.

■ 20. In § 195.402, paragraphs (c)(4), (5), and (12) and (e)(1), (4), (7), and (10) are revised to read as follows:

§ 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 if the facilities failed or malfunctioned, including segments that could affect high-consequence areas (HCA) or are in HCAs, and valves specified in § 195.418 or § 195.452(i)(4).

(5) Investigating and analyzing pipeline accidents and failures, including sending the failed pipe, component, or equipment for laboratory testing or examination where appropriate, to determine the cause(s) and contributing factors of the failure and to minimize the possibility of a recurrence.

(i) *Post-failure and -accident lessons learned.* Each operator must develop, implement, and incorporate lessons learned from a post-failure and accident review into its written procedures, including in pertinent operator personnel training and qualifications programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

(ii) *Analysis of rupture and valve shut-offs; preventive and mitigative measures.* If a failure or accident on an onshore hazardous liquid or carbon dioxide pipeline involves the closure of a rupture-mitigation valve (RMV), as defined in § 195.2, or the closure of an alternative equivalent technology, the operator of the pipeline must also conduct a post-failure or -accident analysis of all of the factors that may have impacted the release volume and the consequences of the release and identify and implement operations and maintenance measures to minimize the consequences of a future failure or incident. The analysis must include all relevant factors impacting the release volume and consequences, 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 supervisory control and data acquisition (SCADA), communications, valve shut-off, and operator personnel;

(C) Actual response time from identifying a rupture following a notification of potential rupture, as defined at § 195.2, to initiation of mitigative actions and isolation of the segment, and the appropriateness and effectiveness of the mitigative actions taken;

(D) Location and timeliness of actuation of all RMVs or alternative equivalent technologies; and

(E) All other factors the operator deems appropriate.

(iii) *Rupture post-failure and accident summary.* If a failure or accident on an onshore hazardous liquid or carbon dioxide pipeline involves the identification of a rupture following a notification of potential rupture; the closure of an RMV, as those terms are defined in § 195.2; or the closure of an alternative equivalent technology, the operator must complete a summary of the post-failure or -accident review required by paragraph (c)(5)(ii) of this section within 90 days of the failure or accident. While the investigation is pending, the operator must conduct quarterly status reviews until the investigation is completed and a final post-failure or -accident review is prepared. The final post-failure or -accident summary and all other reviews and analyses produced under the requirements of this section must be reviewed, dated, and signed by the operator's appropriate senior executive officer. An operator must keep, for the useful life of the pipeline, the final post-failure or -accident summary, all investigation and analysis documents used to prepare it, and records of lessons learned.

* * * * *

(12) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (*i.e.,* 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, and fire, police, and other public officials. Operators must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone numbers for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform the officials about the operator's ability to respond to the pipeline emergency and means of communication during emergencies. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9–1–1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity.

* * * * *

(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 (*i.e.,* 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, and fire, police, and other appropriate public officials, and communicating this information to appropriate operator personnel for prompt corrective action. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9–1–1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity.

* * * * *

(4) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, or 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 must also develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in § 195.2, is an actual rupture event or non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture, as defined at § 195.2. For operators installing valves in accordance with § 195.258(c), § 195.258(d), or that are subject to the requirements in § 195.418, those procedures should provide for rupture identification as soon as practicable.

* * * * *

(7) Notifying the appropriate public safety answering point (*i.e.,* 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, and 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 (HVL). The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdiction(s) in which the pipeline is located after notification of potential rupture, as defined at § 195.2, has occurred to coordinate and share information to determine the location of the release, regardless of whether the segment is subject to the requirements of § 195.258 (c) or (d), § 195.418, or § 195.419.

* * * * *

(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.

* * * * *

■ 21. Section 195.417 is added to read as follows:

§ 195.417 Notification of potential rupture.

(a) As used in this part, a notification of potential rupture means refers to the notification to, or observation by, an operator (*e.g.,* by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of hazardous liquids from a pipeline:

(1) An unanticipated or unexplained pressure loss outside of the pipeline's normal operating pressures, as defined in the operator's written procedures. The operator must establish in its written procedures that an unanticipated or unplanned pressure loss is outside of the pipeline's normal operating pressures when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less, unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in product demand, receipts, or deliveries;

(2) An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting paragraph (a)(1) of this section; or

(3) Any unanticipated or unexplained rapid release of a large volume of hazardous liquid, a fire, or an explosion, in the immediate vicinity of the pipeline.

(b) A notification of potential rupture occurs when an operator first receives notice of or observes an event specified in paragraph (a) of this section.

■ 22. Section 195.418 is added to read as follows:

§ 195.418 Valves: Onshore valve shut-off for rupture mitigation.

(a) *Applicability.* For newly constructed and entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments, as defined at § 195.2, with diameters of 6 inches or greater that could affect high-consequence areas or are located in high consequence areas (HCA), and that have been installed after April 10, 2023, an operator must install or use existing rupture-mitigation valves (RMV), as defined at § 195.2, or alternative equivalent technologies according to the requirements of this section and § 195.419. RMVs and alternative equivalent technologies must be operational within 14 days of placing the new or replaced pipeline segment in service. An operator may request an extension of this 14-day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in § 195.18, that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this section apply to all applicable pipe replacements, even those that do not otherwise directly involve the addition or replacement of a valve.

(b) *Maximum spacing between valves.* RMVs and alternative equivalent technology must be installed in accordance with the following requirements:

(1) *Shut-off Segment.* For purposes of this section, a ''shut-off segment'' means the segment of pipeline located between the upstream valve closest to the upstream endpoint of the replaced pipeline segment in the HCA or the pipeline segment that could affect an HCA and the downstream valve closest to the downstream endpoint of the replaced pipeline segment of the HCA or the pipeline segment that could affect an HCA so that the entirety of the segment that could affect the HCA or the segment within the HCA is between at least two RMVs or alternative equivalent technologies. If any crossover or lateral pipe for commodity receipts or deliveries connects to the replaced segment between the upstream and downstream valves, the shut-off segment also extends to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for commodity to be transported to the rupture site (except for residual liquids already in the shut-off segment). Multiple segments that could affect HCAs or are in HCAs may be contained within a single shut-off segment. All entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments, as defined in § 195.2, that could affect or are in an HCA must include a minimum of one valve that meets the requirements of this section and section 195.419. The operator is not required to select the closest valve to the shut-off segment as the RMV or alternative equivalent technology. An operator may use a manual pump station valve at a continuously manned station as an alternative equivalent technology. Such a manual valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with § 195.18.

(2) *Shut-off segment valve spacing.* Pipeline segments subject to paragraph (a) of this section must be protected on the upstream and downstream side with RMVs or alternative equivalent technologies. The distance between RMVs or alternative equivalent technologies must not exceed:

(i) For pipeline segments carrying non-highly volatile liquids (HVL): 15 miles, with a maximum distance not to exceed 7½ miles from the endpoints of a shut-off segment: or

(ii) For pipeline segments carrying HVLs: 7½ miles. The maximum valve spacing intervals for these valves may be increased by 1.25 times the spacing distance, up to a 9⅜-mile spacing at an endpoint, provided the operator notify PHMSA in accordance with § 195.260 (g).

(3) *Laterals.* Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of these laterals contributing hazardous liquid volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment volume, based upon maximum flow volume at the operating pressure. A check valve may be used as an alternative equivalent technology where it is positioned to stop flow into the lateral. Check valves used as an alternative equivalent technology in accordance with this paragraph are not subject to § 195.419 but must be inspected, operated, and remediated in accordance with § 195.420, including for closure and leakage, to ensure operational reliability. An operator using a such a valve as an alternative equivalent technology must submit a request to PHMSA in accordance with § 195.18.

(4) *Crossovers.* An operator may use a manual valve as an alternative equivalent technology for a crossover connection if, during normal operations, the valve is closed to prevent the flow of hazardous liquid or carbon dioxide with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of hazardous liquid or carbon dioxide. An operator using a such a valve as an alternative equivalent technology must submit a request to PHMSA in accordance with § 195.18.

(c) *Manual operation upon identification of a rupture.* Operators using a manual valve as an alternative equivalent technology pursuant to paragraph (a) of this section must develop and implement operating procedures and appropriately designate and locate nearby personnel to ensure valve shut-off in accordance with this section and § 195.419. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to manually shut off all valves, not to exceed the response time in § 195.419(b).

■ 23. Section 195.419 is added to read as follows:

§ 195.419 Valve capabilities.

(a) *Scope.* The requirements in this section apply to rupture-mitigation valves (RMV), as defined in § 195.2, or alternative equivalent technology, installed pursuant to §§ 195.258 and 195.418.

(b) *Rupture identification and valve shut-off time.* If an operator observes or is notified of a release of hazardous liquid or carbon dioxide that may be representative of an unintentional or uncontrolled release event meeting a notification of potential rupture (*see* §§ 195.2 and 195.417), including any unexplained flow rate changes, pressure changes, equipment functions, or other pipeline instrumentation indications observed by the operator, the operator must, as soon as practicable but within 30 minutes of rupture identification (*see* § 195.402(e)(4)), identify the rupture and fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of hazardous liquid or carbon dioxide released from a pipeline and mitigate the consequences of a rupture.

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

(d) *Valve monitoring and operational capabilities.* An RMV, as defined in § 195.2, or alternative equivalent technology, must be capable of being monitored or controlled by either remote or onsite personnel as follows:

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

(2) Monitored for valve status (*i.e.,* open, closed, or partial closed/open), upstream pressure, and downstream pressure. For automatic shut-off valves

(ASV), an operator does not need to monitor remotely a valve's status if the operator has the capability to monitor pressures or flow rate within each pipeline segment located between RMVs or alternative equivalent technologies to identify and locate a rupture. Pipeline segments that use an alternative equivalent technology must have the capability to monitor pressures and hazardous liquid or carbon dioxide flow rates on the pipeline in order to identify and locate a rupture; and

(3) Have a back-up power source to maintain supervisory control and data acquisition (SCADA) systems or other remote communications for remote-control valve (RCV) or ASV operational status or be monitored and controlled by on-site personnel.

(e) *Monitoring of valve shut-off response status.* The position and operational status of an RMV must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means. An operator does not need to monitor remotely an ASV's status if the operator has the capability to monitor pressures or hazardous liquid or carbon dioxide s flow rate on the pipeline to identify and locate a rupture.

(f) *Flow modeling for automatic shut-off valves.* Prior to using an ASV as an RMV, the operator must conduct flow modeling for the shut-off segment and any laterals that feed the shut-off segment, so that the valve will close within 30 minutes or less following rupture identification, consistent with the operator's procedures, and in accordance with § 195.2 and this section. The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions that may be encountered during the year, not to exceed a period of 15 months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or hazardous liquid or carbon dioxide receipt tie-ins. If operating conditions change that could affect the ASV set pressures and the 30-minute valve closure time following a notification of potential rupture, as defined at § 195.2, an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with § 195.420. The flow model must include a time/pressure chart for the segment containing the ASV if a rupture event occurs. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could render the 30-minute valve closure time unachievable.

(g) *Pipelines not affecting HCAs.* For pipeline segments that are not in a high-consequence area (HCA) or that could not affect an HCA, an operator submitting a notification pursuant to §§ 195.18 and 195.258 for use of manual valves as an alternative equivalent technology may also request an exemption from the valve operation requirements of § 195.419(b).

■ 24. In § 195.420, paragraph (b) is revised and paragraphs (d) through (g) are added to read as follows:

§ 195.420 Valve maintenance.

* * * * *

(b) Each operator must, at least twice each calendar year, but at intervals not exceeding 7½ months, inspect each valve to determine that it is functioning properly. Each rupture-mitigation valve (RMV), as defined in § 195.2, or alternative equivalent technology that is installed under § 195.258(c) or § 195.418, must also be partially operated. Operators are not required to close the valve fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance, unless the operator has operational information that requires an additional closure percentage for maintaining reliability.

* * * * *

(d) For each remote-control valve (RCV) installed in accordance with § 195.258(c) or § 195.418, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with § 195.446(c) and (e).

(e) For each alternative equivalent technology installed under § 195.258(c) or (d) or § 195.418(a) that is manually or locally operated (*i.e.,* not an RMV, as that term is defined in § 195.2):

(1) Operators must achieve a response time of 30 minutes or less, as required by § 195.419(b), through an initial drill and through periodic validation as required by paragraph (e)(2) of this section. An operator must review each phase of the drill response and document the results to validate the total response time, including the identification of a rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification.

(2) Within each pipeline system, and within each operating or maintenance field work unit, operators must randomly select an authorized rupture-mitigation alternative equivalent technology for an annual 30-minute-total response time validation drill simulating worst-case conditions for that location to ensure compliance with § 195.419. Operators are not required to close the alternative equivalent technology fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance with the drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar year, at intervals not to exceed 15 months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph.

(3) If the 30-minute-maximum response time cannot be achieved in the drill, the operator must revise response efforts to achieve compliance with § 195.419 no later than 12 months after the drill. Alternative valve shut-off measures must be in accordance with paragraph (f) of this section within 7 days of the drill.

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

(i) Training and qualifications programs;

(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 remedial measures as follows to correct any valve installed on an onshore pipeline in accordance with § 195.258(c), or an RMV or alternative equivalent technology installed in accordance with § 195.418, that is indicated to be inoperable or unable to maintain effective shut-off:

(1) Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain shut-off. An operator may request an extension of the compliance deadline requirements of this section if it can demonstrate to PHMSA, in accordance with the notification procedures in § 195.18, that repairing or replacing a valve within 12 months would be economically, technically, or operationally infeasible; and

(2) Designate an alternative compliant valve within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Alternative compliant valves are not required to

comply with valve spacing requirements of this part.

(g) An operator using an ASV as an RMV, in accordance with §§ 195.2, 195.260, 195.418, and 195.419, must document, in accordance with § 195.419(f), and confirm the ASV shut-in pressures on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required by § 195.419(f), at least each calendar year, but at intervals not to exceed 15 months.

■ 25. In § 195.452, paragraph (i)(4) is revised to read as follows:

§ 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 that is located in, or which could affect, a high-consequence area (HCA) in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, evaluate 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 within the HCA or between the pipeline segment and the HCA it could affect, and benefits expected by reducing the spill size. An RMV installed under this paragraph must meet all of the other applicable requirements in this part.

(i) Where EFRDs are installed on pipeline segments in HCAs and that could affect HCAs with diameters of 6 inches or greater and that are placed into service or that have had 2 or more miles of pipe replaced within 5 contiguous miles within a 24-month period after April 10, 2023, the location, installation, actuation, operation, and maintenance of such EFRDs (including valve actuators, personnel response, operational control centers, supervisory control and data acquisition (SCADA), communications, and procedures) must meet the design, operation, testing, maintenance, and rupture-mitigation requirements of §§ 195.258, 195.260, 195.402, 195.418, 195.419, and 195.420.

(ii) The EFRD analysis and assessments specified in this paragraph (i)(4) must be completed prior to placing into service all onshore pipelines with diameters of 6 inches or greater and that are constructed or that have had 2 or more miles of pipe within any 5 contiguous miles within any 24-month period replaced after April 10, 2023. Implementation of EFRD findings for RMVs must meet § 195.418.

(iii) An operator may request an exemption from the compliance deadline requirements of this section if it can demonstrate to PHMSA, in accordance with the notification procedures in § 195.18, that installing an EFRD by that compliance deadline would be economically, technically, or operationally infeasible.

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