

**BEFORE THE  
UNITED STATES DEPARTMENT OF TRANSPORTATION  
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION  
WASHINGTON, D.C.**

Pipeline Safety: Valve Automation & Minimum  
Rupture Detection Standards



Docket No. PHMSA-2013-0255

**COMMENTS**

**FILED BY  
AMERICAN GAS ASSOCIATION  
AMERICAN PETROLEUM INSTITUTE  
AMERICAN PUBLIC GAS ASSOCIATION  
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA**

April 6, 2020

**Table of Contents**

I. Introduction ..... 1

II. PHMSA Should Clarify Which Aspects of the Proposed Rule Apply to Distribution Pipelines ..... 2

III. PHMSA Should Revise and Clarify §§ 192.179 and 192.634(a) to be Fit-for-Purpose for Remote Locations and Low-Risk Pipelines ..... 3

IV. PHMSA Should Develop a More Efficient Approach to Managing Pipe Replacements Under § 192.610 ..... 12

V. PHMSA Should Revise the Proposed Automated Valve Performance Standards to Avoid Unnecessary Service Disruptions and Accommodate the Full Breadth of Gas Transmission Pipeline Operations Scenarios ..... 16

VI. PHMSA Should Modify § 192.634(b) to Allow the Use of Additional Technologies and Practices .... 20

VII. PHMSA Should Reconsider the Proposed Maintenance Requirements for when a Rupture-Mitigation Valve is Unable to Achieve the Performance Standard and Clarify the Proposed Drill Requirements..... 25

VIII. The Associations Recommend Changes to § 192.617 to Ensure Requirements are Clear..... 28

IX. PHMSA Should Remove § 192.935(c)(1)-(2) ..... 30

X. Changes to Alternative MAOP Requirements Should Be Prospective Only ..... 31

XI. The Performance Requirements in Proposed § 192.634 Are Not Appropriate or Practical for Existing Pipelines ..... 31

XII. Consolidated Recommendations for Changes to Regulatory Text of Proposed Rule ..... 33

## I. Introduction

The American Gas Association (AGA),<sup>1</sup> American Petroleum Institute (API),<sup>2</sup> American Public Gas Association (APGA),<sup>3</sup> and Interstate Natural Gas Association of America (INGAA)<sup>4</sup> (jointly “the Associations”) submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) regarding the gas pipeline provisions of PHMSA’s Notice of Proposed Rulemaking, “Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards” (“Proposed Rule” or “NPRM”).<sup>5</sup>

Pipeline safety is the top priority of the Associations and our members. In general, the Associations support PHMSA’s proposal to require the use of automated valve technology on new gas transmission pipelines and significant replacement projects (note: the Associations use the term “automated valve” to refer broadly to automatic shutoff valves, remote-control valves, and equivalent technology). While pipeline emergencies are rare, operators must be prepared for a quick and safe response. Automated valve technology can be a valuable incident response tool where it is technically and operationally feasible and effectively reduces risk.

Below, the Associations offer detailed comments to assist PHMSA in developing a final rule that enhances pipeline safety, provides clear requirements, and leads to an efficient use of pipeline operators’ resources. The Associations wish to highlight the following key recommendations:

---

<sup>1</sup> The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 74 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent — over 71 million customers — receive their gas from AGA members. Today, natural gas meets more than one-fourth of the United States' energy needs.

<sup>2</sup> API is the national trade association representing all facets of the oil and natural gas industry, which supports 9.8 million U.S. jobs and 8 percent of the U.S. economy. API’s more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation’s energy and are backed by a growing grassroots movement of more than 25 million Americans.

<sup>3</sup> APGA is the national, non-profit association of publicly-owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 740 members in 37 states. Overall, there are nearly 1,000 municipally-owned systems in the U.S. serving more than five million customers. Publicly-owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

<sup>4</sup> INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 27 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA’s members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

<sup>5</sup> Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards, 85 Fed. Reg. 7,162 (Feb. 6, 2020).

1. PHMSA should limit new distribution system requirements to 9-1-1 call center liaison/notifications and incorporation of post-incident lessons learned.
2. PHMSA should clarify that the valve automation requirements for class 1 and 2 locations outside of High Consequence Areas (HCAs) are opportunistic and do not require automation of upstream/downstream valves.
3. PHMSA should apply § 192.634 only to class 3, 4, and HCA locations to allow more flexibility in remote areas.
4. PHMSA should clarify that operators are not required to install new manual or automated valves when replacing less than two miles of pipe, with the exception of replacements covered by § 192.610.
5. PHMSA should exclude pipelines that have a Maximum Allowable Operating Pressures (MAOP) less than 30% of SMYS or a Potential Impact Radius (PIR) less than or equal to 150 feet from the proposed automated valve requirements.
6. PHMSA should revise proposed § 192.610 to allow operators to automate existing valves instead of installing new valves when class location changes occur.
7. PHMSA should eliminate the ten-minute “identification” requirement because the proposed 40-minute response standard is sufficient to ensure the safety of gas transmission pipelines in class 3, 4, and HCA locations.
8. PHMSA should require operators to establish specific rupture notification criteria for each pipeline, rather than applying the same pressure drop criterion to all pipelines.
9. PHMSA should modify § 192.634(b) to allow the use of additional technologies and practices.
10. PHMSA should reconsider certain aspects of the proposed maintenance requirements for when a rupture-mitigation valve is unable to achieve the performance standard.

## II. PHMSA Should Clarify Which Aspects of the Proposed Rule Apply to Distribution Pipelines

The NPRM preamble does not discuss how distribution lines are impacted by the proposed changes. The Preliminary Regulatory Impact Analysis (PRIA) indicates that the changes to Part 192 are limited to gas transmission pipelines and hazardous liquid lines.<sup>6</sup> For example, the PRIA states that “Based on 2016 annual report data, PHMSA identified 1,038 gas transmission operators and 484 hazardous liquid pipeline operators with onshore transmission lines that would be subject to these new requirements (Table 4-2).”<sup>7</sup>

There are several proposed changes, however, that appear applicable to both transmission and distribution pipelines, as shown in Table 1 below.

---

<sup>6</sup> Preliminary Regulatory Impact Analysis at 23, § 4, Table 4-1.

<sup>7</sup> *Id.* at § 4.1

**Table 1: Proposed Rule Provisions that Appear to Apply to Distribution Pipelines**

§192.3	Definition of ‘Rupture’
§192.615	(a)(2) Emergency Plan Communications (a)(6) Emergency Plan Actions (a)(8) Emergency Plan Coordination (c) Emergency Plan Liaison
§192.617	(b) Post Incident Lessons Learned (c) Analysis of Rupture (d) Rupture Post-Incident Summary

The Associations will address the applicability to distribution pipelines of each of these proposed requirements in greater detail in the respective sections of the comments below. The Associations recommend that PHMSA limit new distribution system requirements to 9-1-1 call center liaison/notifications and incorporation of post-incident lessons learned.

III. PHMSA Should Revise and Clarify §§ 192.179 and 192.634(a) to be Fit-for-Purpose for Remote Locations and Low-Risk Pipelines

**A. PHMSA should clarify that § 192.179(e) is opportunistic and does not require automation of upstream/downstream valves.**

The Associations request that PHMSA make clarifying edits to proposed § 192.179(e) to more clearly differentiate the requirements for pipelines in class 1 and 2 non-HCA locations (§ 192.179(e)) from those in class 3, 4 and HCA locations (§ 192.634(b)).

It appears that PHMSA’s intent in proposed § 192.179(e) is for operators to install an automated valve whenever it is necessary to install a new valve to comply with the spacing requirements in existing § 192.179(a) (as part of new construction or replacement of two miles or more). In other words, automated valve requirements for pipelines in class 1 and 2 non-HCAs will be “opportunistic”; valve automation will not be required if the construction or replacement project does not involve a valve, regardless of the length of pipe installed. This is different from the requirements for pipelines in class 3, 4, and HCA locations under § 192.634(b), which will require upstream and downstream automated valves for new construction and two-plus-mile replacements regardless of whether the project involves a valve installation. In Subsection C below, the Associations recommend clarifying edits to §192.179(e) to better distinguish it from § 192.634(b).

This distinction between pipelines in class 1 and 2 non-HCA locations (§ 192.179(e)) versus those in class 3, 4 and HCA locations (§ 192.634(b)) is appropriate. Automated valves are a mitigative measure, and therefore the primary benefit provided by automated valves is realized in locations where there are people and property. The National Transportation Safety Board (NTSB) has recognized this, recommending the installation of automated shutoff valves for pipelines in class 3, 4 and HCA locations.<sup>8</sup> Similarly, the Government Accountability Office (GAO) has noted that “the advantages and disadvantages of installing an automated valve are closely related to the specifics of the valve’s

<sup>8</sup> NATIONAL TRANSPORTATION SAFETY BOARD, *Safety Recommendation P-11-011*, (Sep. 26, 2011), [https://www.nts.gov/ layouts/nts.recsearch/Recommendation.aspx?Rec=P-11-011](https://www.nts.gov/layouts/nts.recsearch/Recommendation.aspx?Rec=P-11-011).

location.”<sup>9</sup> Furthermore, Oak Ridge National Labs has determined that “without fire fighter intervention, the swiftness of block valve closure has no effect on mitigating potential fire damage to buildings and personal property.”<sup>10</sup> Emergency responder intervention is likely to be more expedient in more populated areas, justifying the allocation of resources towards automated valves on pipelines in class 3, 4, and HCA locations.

Automating an existing valve that is not involved in a replacement project (i.e., a valve upstream or downstream of the replacement project) can be both technically challenging and expensive, which supports focusing such efforts in class 3, 4, and HCA locations. Aside from the actuator itself, power and communication lines may need to be routed to the valve, and the manual valve site may not have the requisite space to accommodate the new equipment. These considerations would necessitate a new valve location. The Associations estimate that the average cost to automate two existing valves to comply with § 192.634(b) will range from \$300,000 to \$600,000 for both valves.<sup>11</sup> These costs may be appropriate in densely-developed areas, but they are not commensurate with risk in more remote areas. The imbalance between cost and risk reduction justifies PHMSA’s bifurcated approach for pipelines in non-HCA class 1 and 2 locations versus those located in class 3, class 4 and HCAs.

The high costs of automating existing upstream and downstream valves surrounding pipeline segments in class 1 and 2 non-HCA locations would create a disincentive for voluntary pipe replacements in class 1 and 2 non-HCA locations. When prioritizing work within a given operator’s pipeline safety budget, the operator would have to consider not only the resources required to make the replacement, but the valve automation costs as well. The likely result is that an operator may make fewer voluntary pipe replacements because each replacement would cost significantly more than today. This does not seem like an appropriate trade-off in less-populated areas where automated valves provide less safety value. Thus, PHMSA should clarify that the automated valve requirements for pipelines in class 1 and 2 non-HCAs are opportunistic, only requiring valve automation where the construction or replacement project already involves the installation of new valves to comply with § 192.179(a).

***B. PHMSA should apply § 192.634 only to pipelines in class 3, 4, and HCA locations to allow more flexibility in remote areas.***

PHMSA should limit the applicability of § 192.634 only to pipeline segments in class 3, 4, and HCA locations. Section 192.634 provides highly prescriptive requirements for the operation and performance of automated valves. The higher potential consequences in class 3, 4, and HCA locations render these prescriptive requirements more appropriate for such locations. However, these requirements are less beneficial and more challenging to achieve in less-populated areas. Specifically, the 40-minute response time required by § 192.634(c), (e), and (f) is significantly more challenging to achieve in remote areas. A 40-minute response time may be appropriate in many scenarios, but it simply isn’t feasible in some remote locations where gas transmission pipelines operate.

---

<sup>9</sup> GOVERNMENT ACCOUNTABILITY OFFICE, PIPELINE SAFETY, BETTER DATA AND GUIDANCE NEEDED TO IMPROVE PIPELINE OPERATOR INCIDENT RESPONSE (Jan. 2013), available at <https://www.regulations.gov/document?D=PHMSA-2013-0255-0002>.

<sup>10</sup> OAK RIDGE NATIONAL LABORATORY, 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 at xxiv (Oct. 31, 2012), available at <https://www.regulations.gov/document?D=PHMSA-2013-0255-0004>.

<sup>11</sup> Based on a survey of operators representing more than 120,000 miles of gas transmission pipelines.

Response time should not be one-size-fits-all. To ensure a reasonable final rule, PHMSA should provide a path in § 192.179(e) for situations where a 40-minute response time is not practicable or necessary for safety. Operators are likely to consider the use of manual valves in remote areas because an automatic shutoff valve, a remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible, consistent with proposed § 192.179(e). Running power or communications to an automated valve can be significantly more challenging in remote areas. For example, laterals that connect to storage facilities or end users often run through remote areas away from the main pipeline right-of-way, where power and communications infrastructure tends to be located. But § 192.634(c), (e), and (f), as proposed, would prevent an operator from using a manual valve in many remote areas that cannot be reached by operations personnel within 40 minutes. Pipelines transverse a multitude of geographies, including locations that cannot safely be reached within 40 minutes, particularly during winter months.

Furthermore, using an automated valve in a remote area may create an increased reliability risk than using an automated valve in a more populated area. If a communications failure, power loss, or other malfunction causes an automated valve in a remote area to close unnecessarily (i.e., in the absence of a rupture), it may take the operator hours to arrive at the valve and restore service, leading to an extended loss of gas supply to entire communities, power generation facilities, or manufacturers. If natural gas appliance pilot lights have to be relit, the hours for return to service can become days. Thus, in remote areas, the reliability-related consequences of an unnecessary automated valve closure may often outweigh the safety benefits of a 40-minute response time.

Similarly, even where an operator employs a remote-control valve to meet the requirement in § 192.179(e) in a class 1 or 2 location, it will take more time for the operator to acquire information about a potential rupture event in remote areas (for example, reports from company personnel, first responders, etc. may take longer). This renders the 40-minute response time far less feasible in class 1 and 2 locations than in class 3, 4, and HCA locations. Operators require significant information about a potential rupture event before making the critical decision to close a remote-control valve—closing a valve prematurely can have the same disruptive impacts to customers as in the case of a valve malfunction discussed above.

Limiting § 192.634 to pipelines in class 3, 4, and HCA locations would also improve the clarity of the Proposed Rule. The cross-references to § 192.634 in § 192.179(e) of the Proposed Rule create significant confusion as currently drafted. For example, proposed § 192.179(e) appears to exempt class 1 and 2 non-HCA locations from the requirements in proposed § 192.634(b) and (e). The other references to § 192.634 in § 192.179(e), however, conflict with these exemptions. Specifically, § 192.179(e) requires compliance with § 192.634(d) for pipelines in class 1 and 2 non-HCA locations, and § 192.634(d) references § 192.634(b), which requires prescriptive valve spacing requirements. Similarly, § 192.179(e) requires compliance with § 192.634(f), which in turn references back to § 192.634(e). Although the Associations do not believe that PHMSA intends to require pipelines in class 1 and 2 non-HCAs to comply with § 192.634(b) or (e), the cross-references noted above demonstrate the confusion created by linking § 192.179(e) to § 192.634.

If PHMSA limits the applicability of § 192.634 to pipelines in class 3, 4 and HCA locations, the Proposed Rule still contains numerous other provisions that will ensure effective performance of automated valves installed in class 1 and 2 non-HCA locations. Operators would still be required to install

automated valves under § 192.179(e), comply with the standards for notification of a potential rupture in § 192.3, implement emergency planning requirements under § 192.615, conduct post-incident reviews and implement preventative and mitigative measures under § 192.617, and implement maintenance requirements under § 192.745.

Consistent with the recommendation to limit proposed § 192.634 to pipelines in class 3, 4, and HCA locations, the Associations also recommend moving proposed § 192.634(h) to § 192.179(f) so that the alternative technology or manual valve notification process still applies to all locations. The Associations emphasize that operators installing new or replaced pipelines in remote areas are likely to utilize this notification process. The Associations encourage PHMSA to be receptive to such notifications so that the Proposed Rule is not overly burdensome for projects in remote areas.

***C. PHMSA should clarify that the valve spacing requirements of § 192.179 do not apply to pipeline replacements that comply with the rupture-mitigation valve spacing requirements in § 192.634(b).***

To ensure clarity in the regulations, PHMSA should explicitly state in § 192.179 that the valve spacing requirements of that section do not apply to pipeline replacements that comply with the rupture-mitigation valve spacing requirements in § 192.634(b). Otherwise, the Proposed Rule could be interpreted to require operators that replace two or more miles of pipe to install new valves to comply with the spacing requirements of § 192.179(a) in addition to the valve automation requirements of § 192.634. This would render the valve spacing requirements of § 192.634(b) meaningless.

In § 192.634(b), PHMSA allows operators to space automated valves for replacement projects in class 3, 4, and HCA locations based on an assumed “one-class bump” (Class 1 to a Class 2, a Class 2 to a Class 3, or a Class 3 to a Class 4 change). PHMSA states that the intent of this provision is to “allow[] operators to use the valve spacing required in § 192.179 for the previous class location when creating shut-off segments where the class location has recently changed.”<sup>12</sup> This indicates that PHMSA does not intend for operators to install new valves to comply with the valve spacing requirements in § 192.179(a) for replacement projects that comply with § 192.634(b). This is confirmed by PHMSA’s PRIA, which does not account for the addition of any new valves to comply with the Proposed Rule.

A replaced pipeline that has upstream and downstream automated valves spaced in accordance with § 192.634(b) will be able to respond rapidly to any rupture—the difference in spacing between § 192.179(a) and § 192.634(b) will not affect the effectiveness of emergency response where valves are automated. As discussed in more detail in Part IV below, the resources required to automate existing valves are much more reasonable than those required to install a new valve during each pipe replacement. And the materials needed to automate existing valves are often much more readily available than a new valve. Valve operators for older valves will require special designs and custom equipment. For larger diameter valves, lead times can be up to one year.

In Section III.I below, the Associations propose a new § 192.179(g) to provide the requested clarification. The Associations’ proposed clarification would not affect the spacing requirements for new construction.

---

<sup>12</sup> Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards, 85 Fed. Reg. at 7,174.



***D. PHMSA should clarify that operators are not required to install new valves when replacing less than two miles of pipe, with the exception of replacements covered by § 192.610.***

It appears that PHMSA does not intend to require the installation of new valves or the automation of existing valves for pipe replacements that are less than two contiguous miles and fall outside of proposed § 192.610. However, PHMSA should explicitly clarify this point in § 192.179.

Section 192.610 is the only section of the proposed rule that addresses replacements of pipe that are less than two contiguous miles. The Proposed Rule appears to require the installation of manual valves during class location change pipe replacements of segments shorter than two contiguous miles that do not comply with the valve spacing requirements of §§ 192.179 or 192.634. Section 192.610 explicitly applies only to pipeline replacements that have occurred as the direct result of a class location change to comply with § 192.611. Furthermore, PHMSA’s enforcement history regarding § 192.179 does not indicate any instances where the agency required an operator to install new valves during a replacement project unless the project was directly caused by a class location change. However, operators often replace short segments of pipe for maintenance and integrity management purposes—not due to a class location change—where the existing pipe does not comply with the new construction valve spacing requirements of § 192.179. (For example, the existing pipe may not comply with § 192.179 spacing because the pipeline was installed prior to the promulgation of § 192.179 in 1970 or because a one-class location change occurred that did not require a pipe replacement.) Thus, it appears that PHMSA does not intend to require the installation of new valves or the automation of existing valves for pipe replacements that are less than two contiguous miles and that fall outside of proposed § 192.610.

Operators frequently replace a short section of existing pipe to repair potentially injurious conditions found to be affecting that short section of pipe. These maintenance replacements are not “pipe replacement projects” in the traditional sense—only small sections of pipe are affected. In some cases, maintenance pipe replacements must be conducted immediately to ensure public safety. The operator cannot delay remediation of a potentially injurious condition because it is waiting on a long-lead valve to arrive. It is common sense that operators must be able to repair pipeline defects without installing additional valves.

Operators may also replace small segments of pipe in order to allow the pipeline to accommodate in-line inspection, to reconfirm MAOP, or to conduct other operations and maintenance activities. Soon-to-be codified § 192.710 will expand the use of integrity assessment programs, which will spur additional assessments and an increase in maintenance/integrity-driven pipe replacements in the future.<sup>13</sup> All stakeholders agree that assessment and remediation programs are among the most effective means to ensure pipeline safety. Requiring all replacements, no matter how small, to comply with valve spacing requirements applicable to new pipe construction would increase the cost and regulatory complexity of the new requirements and may reduce an operator’s incentive or ability to complete voluntary assessments and remediations.

Applying the valve spacing requirements to all pipeline replacements raises significant concerns under the Pipeline Safety Act’s non-retroactivity provision and does not have consistent support in PHMSA’s

---

<sup>13</sup> See Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 Fed. Reg. 52,180, 52,250 (Oct. 1, 2019).

rulemaking history. PHMSA is prohibited by statute from applying new pipeline design and construction requirements to existing pipe,<sup>14</sup> and concerns about whether PHMSA's design and construction regulations should apply to short, maintenance pipe replacements date to the earliest days of the federal pipeline safety program. In 1971, only one year after the adoption of Part 192, the members of the Technical Pipeline Safety Standards Committee (the Committee) expressed concern with the application of § 192.13(b) in the context of short replacements of cast iron pipe. The Committee members stated that, according to a strict reading of the regulations, operators of cast iron pipelines would need to use steel for any replacement and the joining of steel and cast iron would accelerate corrosion risks.<sup>15</sup> The Committee members stated that without an exception from § 192.13(b) for cast iron replacements, operators would be discouraged from replacing pipe.<sup>16</sup> The Agency's counsel at the time confirmed that this was an issue and stated that "[w]e can put in something like 'other than short sections of replacement pipe that are installed' or something to make clear that this does not apply to replacement pipe."<sup>17</sup> Counsel also stated that "[w]e will have to make clear in the regulations what we mean by replacement and what we mean by new installation. . . . We realize there is a problem."<sup>18</sup> However, there is no indication that PHMSA took further action to address maintenance replacements after these initial discussions in 1971.

Similarly, in 2002, PHMSA issued an interpretation to the Public Utilities Commission of Ohio (PUCO).<sup>19</sup> As part of its request to understand the Operator Qualification requirements, PUCO had asked the Agency whether the replacement of the entire length of a failed customer-owned portion of a service line was considered an O&M task or new construction. In its response, PHMSA stated the following: "The replacement of a service line with new pipe, whether by insertion or direct burial, is an operations and maintenance (O&M) activity . . . It is not new construction because it is designed to maintain the serviceability of an existing service line."<sup>20</sup> If replacing a failed service line is not considered new construction, it is questionable why any in-kind pipe replacement to remediate integrity concerns or to comply with PHMSA's O&M regulations on a natural gas transmission line would be considered new construction.

Thus, PHMSA should take the opportunity presented by this rulemaking to clarify the valve-related requirements for maintenance replacements (that is, those not due to a class location change) that are less than two contiguous miles. Otherwise, the Proposed Rule, as currently drafted, will create confusion regarding the maintenance replacement-related requirements under § 192.179. PHMSA should not add new automated valve requirements without also ensuring that the underlying valve spacing requirements in Part 192 are clear.

---

<sup>14</sup> Natural Gas Pipeline Safety Act of 1968, Pub. L. No. 90-481 § 3, 82 Stat. 720, 721 (1968) (codified at 49 U.S.C. § 60104(b)).

<sup>15</sup> Transcript of Proceedings at 98-99, Technical Pipeline Safety Standards Committee (April 13, 1971).

<sup>16</sup> *Id.*

<sup>17</sup> *Id.* at 109-110.

<sup>18</sup> *Id.* at 115.

<sup>19</sup> PHMSA Letter of Interpretation to Mr. Edward Steel, Chief, Gas Safety Section, Public Utilities Commission of Ohio, PI-02-0101 (Sept. 18, 2002).

<sup>20</sup> *Id.* (emphasis added).

***E. PHMSA should exclude pipelines with MAOPs less than 30% of SMYS from the proposed automated valve requirements.***

The Associations recommend that PHMSA limit the scope of § 192.179(e) and § 192.634(a) to pipelines with MAOPs greater than or equal to 30% of SMYS. Stakeholders generally accept 30% of SMYS as the “low-stress” boundary between leaks and ruptures for pipeline defects. Because the goal of this rulemaking is to accelerate response to pipeline ruptures, it is appropriate to limit this rule to the subset of pipelines that are generally susceptible to rupture. Studies conducted by the Gas Technology Institute, Battelle and Kiefner & Associates have validated that pipelines which operate at pressures less than 30% SMYS are below the leak-rupture boundary and generally leak rather than rupture when they fail.<sup>21</sup> The Associations believe that by limiting the scope of the proposed requirements to pipelines that operate at pressures greater than 30% SMYS, PHMSA would appropriately target and reduce the consequences of ruptures.

Installing automated valves is not necessary or appropriate for managing the leaks that occur on pipelines with MAOPs below 30% of SMYS. PHMSA’s existing regulations address leaks by requiring the periodic monitoring of leaks (§ 192.706) and the repair of hazardous leaks (§§ 192.703, 192.711, and 192.713). Requiring automated valves to address leaks on low-SMYS pipelines is resource-intensive, could potentially result in large customer outages if valves close inadvertently (that is, not due to a rupture event), and would have minimal safety benefits.

Furthermore, limiting the applicability of the Proposed Rule to pipelines with MAOPs greater than 30% SMYS is consistent with many other parts of Part 192. For example, PHMSA’s new MAOP reconfirmation requirements for grandfathered pipes in § 192.624 are limited to pipelines with MAOPs greater than or equal to 30% of SMYS, as are the new requirements in § 192.710 to conduct recurring integrity assessments of pipelines in class 3, 4, and MCA locations. These new code sections were limited to pipelines operating at or above 30% SMYS following a Gas Pipeline Advisory Committee discussion and recommendation regarding the leak-rupture boundary.<sup>22</sup> Numerous other code sections are limited to pipelines operating above 30% of SMYS, including § 192.233, aspects of § 192.503(c), § 192.505, § 192.555, aspects of § 192.935, and aspects of § 192.939.

For these reasons, the Associations recommend that PHMSA should exclude pipelines with MAOPs less than 30% of SMYS from the proposed automated valve requirements.

***F. PHMSA should exclude pipelines with PIRs less than or equal to 150 feet from the proposed automated valve requirements.***

PHMSA should exclude pipelines with PIRs less than or equal to 150 feet from the proposed automated valve requirements. Pipeline diameter alone is not an accurate indicator of the potential consequences of a pipeline rupture. Many 6”, 8”, 10”, and even 12” pipelines operate at low pressures such that the

---

<sup>21</sup> See Kiefner & Associates, Inc., Leak vs. Rupture Thresholds for Material and Construction Anomalies (Dec. 2013) (work completed under contract for INGAA and AGA); Gas Technology Institute, Leak-Rupture Boundary Determination Project, Final Report (May 2011); Battelle Memorial Institute, Integrity Characteristics for Vintage Pipelines (Oct. 2004) (work completed under contract for the INGAA Foundation and the AGA Foundation).

<sup>22</sup> Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 Fed. Reg. at 52,228.

impact of a pipeline rupture would be minimal. PIR reflects both pipeline size and operating pressure and is therefore a better measure of potential consequence than diameter.

PHMSA recognized the relevance of PIR in the recent MAOP Reconfirmation, Expansion of Assessment Requirements Final Rule.<sup>23</sup> That rule requires operators to conduct MAOP reconfirmation on certain pipelines. One allowable MAOP reconfirmation method is to reduce the pipeline's MAOP. For most pipelines, a 20% pressure reduction is required.<sup>24</sup> However, only a 10% pressure reduction is required for pipelines with a PIR less than or equal to 150 feet.<sup>25</sup> PHMSA originally included an 8-inch diameter threshold for the 10% reduction option, but the diameter threshold was removed based on comments during the GPAC deliberations that PIR was a more accurate indicator of consequence.<sup>26</sup>

If PHMSA elects not to add a PIR-based exception, then PHMSA should raise the 6" threshold and limit the proposed rule to new and replaced pipelines greater than 12" in diameter. This would avoid focusing valve-automation efforts and resources on lower-consequence transmission pipelines and would be consistent with prior INGAA commitments.<sup>27</sup> However, the PIR-based exclusion would be a more accurate, risk-informed approach.

***G. PHMSA should allow 24 months to comply with the automated valve requirements to account for existing projects and procurement time.***

PHMSA should require operators to implement the proposed automated valve requirements for newly-constructed and replaced pipe installed 24 months after the effective date of the Proposed Rule. PHMSA's proposed twelve-month timeline is insufficient because many replacement projects are scheduled and planned more than a year in advance, and valve lead times are often many months, and sometimes up to a year or more, excluding the time required to design and construct the valve installation project. Providing a 24-month implementation timeline will allow operators sufficient time to update procurement practices and develop relevant automated valve procedures without disrupting or delaying ongoing construction and replacement projects.

***H. PHMSA should allow operators 14 days to make rupture-mitigation valves operational following the in-service date of a newly-constructed or replaced pipeline.***

It is not always practicable to make rupture-mitigation valves operational within seven days of placing the new or replaced pipeline segment in service, as proposed in § 192.634(a). Numerous safety and operational activities must take place following the introduction of gas into a new pipeline segment, often necessitating more than seven days to make rupture-mitigation valves operational. These activities include testing control and communications systems, conducting management of change processes, and ensuring no system constraints exist which could impact capacity and the delivery of natural gas to end users.

---

<sup>23</sup> *Id.* at 52,180.

<sup>24</sup> 49 C.F.R. § 192.624(c)(2).

<sup>25</sup> 49 C.F.R. § 192.624(c)(5).

<sup>26</sup> Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722, 20,836 (Apr. 8, 2016).

<sup>27</sup> See Comments of INGAA on Pipeline Safety: Public Comment on Leak and Valve Studies Mandated by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, No. PHMSA-2012-0021-0014 (May 1, 2012), <https://www.regulations.gov/document?D=PHMSA-2012-0021-0014>.

For example, the progression of commissioning a new pipeline includes the purge and load of a pipeline segment to provide the natural gas needed to start up compressor units. The time frames to load a pipeline segment to complete the testing and commissioning of a compressor station can take a week or more. Furthermore, inherent in commissioning new compression is the testing of control systems, which can require the compressor unit to be started and stopped many times. This sequence may result in pressure changes on the associated pipeline segments and possible closure of automated valves. Thus, it is often not appropriate to activate automated valves until after the loading of the pipeline and commissioning of compression, which can exceed seven days. Additionally, even a few days of inclement weather following the pipeline start-up could render the proposed seven-day timeline impracticable.

Therefore, PHMSA should allow operators 14 days to make rupture-mitigation valves operational following the in-service date of a newly-constructed or replaced pipeline. There will also be occasional scenarios where more than 14 days are needed—for example, if there is a malfunction of the valve during commissioning or another unexpected construction issue/emergency. PHMSA should provide a notification process for such circumstances.

#### *I. Suggested revisions to proposed rule*

To achieve the objectives outlined above, the Associations recommend the additions to proposed §§ 192.179 and 192.634(a) that are shown **in red** below:

#### **§ 192.179 Transmission line valves.**

[ . . . ]

- (e) **For** all onshore transmission line segments with diameters greater than or equal to 6 inches that are **newly** constructed or **where 2 or more contiguous miles have been entirely** replaced after **[DATE 24 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE]**, **the operator** must **install** ~~have~~ automatic shutoff valves, remote-control valves, or equivalent technology **whenever an additional valve must be** installed ~~at intervals to~~ **meeting** the appropriate valve spacing requirements of this section. An operator may only install a manual valve under this paragraph if it can demonstrate to PHMSA that installing an automatic shutoff valve, remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. An operator using alternative equivalent technology or **a** manual valve must notify PHMSA in accordance with the procedure in **paragraph (f).** ~~§ 192.634(h). All valves and technology installed under this paragraph must meet the requirements of § 192.634(c), (d), (f), and (g). This subsection does not apply to segments that have an MAOP less than 30 percent of the specified minimum yield strength or a potential impact radius (PIR) less than or equal to 150 feet.~~
- (f) **Alternative equivalent technology or manual valves. If an operator elects to use alternative equivalent technology or a manual valve in accordance with paragraph (e), the operator must notify PHMSA at least 90 days in advance of installation or use in accordance with § 192.18. The operator must include a technical and safety evaluation in its notice to PHMSA, including design, construction, and operating procedures for the alternative equivalent technology or manual valve. Operators installing manual valves must also demonstrate that installing an automatic shutoff valve, a remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. An operator may proceed to use the alternative equivalent technology or manual valve 91 days after submitting the notification unless it receives a letter from the Associate Administrator of Pipeline Safety informing the operator that PHMSA objects to the**

proposed use of the alternative equivalent technology or manual valve or that PHMSA requires additional time to conduct its review.

- (g) Replacements. Nothing in this section applies to replacements of existing pipeline segments involving less than two miles of contiguous pipe, except as required under § 192.610. The valve spacing requirements of this section do not apply to pipeline replacements that comply with the rupture-mitigation valve spacing requirements in § 192.634(b).

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

- (a) *Applicability.* For onshore transmission pipeline segments with nominal diameters of 6 inches or greater in high consequence areas or Class 3 or Class 4 locations that are **newly** constructed or where 2 or more contiguous miles have been replaced after [DATE **24 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE**], an operator must install **or use existing** rupture-mitigation valves according to the requirements of this section. Rupture-mitigation valves must be operational within **14 7** days of placing the new or replaced pipeline segment in service, **unless the operator notifies PHMSA in accordance with § 192.18 that a rupture-mitigation valve cannot be made operational within 14 days. This section does not apply to segments that have an MAOP less than 30 percent of the specified minimum yield strength or to segments outside of high consequence areas that have a potential impact radius (PIR) less than or equal to 150 feet.**

[ . . . ]

**IV. PHMSA Should Develop a More Efficient Approach to Managing Pipe Replacements Under § 192.610**

- A. *Proposed § 192.610 would shift tremendous resources towards a minimal amount of pipeline mileage. This inefficient approach would inhibit higher-value, system-wide safety enhancements.***

As currently drafted, proposed § 192.610 would require the allocation of substantial resources towards class location change pipe replacement projects because § 192.610 would require operators to install new valves in conjunction with many class location change replacements. The Associations have previously noted the disproportionate costs associated with PHMSA's fifty-year-old class location change regulations—operators currently allocate \$200–\$300 million per year to class change pipe replacements.<sup>28</sup> Despite these substantial expenditures, class change replacements produce minimal pipeline safety benefits because they involve less than 75 miles (0.025%) per year of transmission pipe, and the replaced pipe is often in safe, operable condition.<sup>29</sup> The Associations commend PHMSA for considering an update to its class location change regulations in a separate rulemaking that may allow operators to employ an integrity management-based approach to managing class location changes.<sup>30</sup> Such an approach would leverage modern technologies and practice to improve the safety of the entire pipeline system, not only the short segment where the class location happens to have changed.

However, as drafted, proposed § 192.610 would divert the class location change program in the wrong direction. It will make class location change pipe replacements even more resource-intensive than

---

<sup>28</sup> Comments of AGA, APGA, API and INGAA on Class Location Change Requirements, No. PHMSA-2017-0151 (Oct. 1, 2018), <https://www.regulations.gov/document?D=PHMSA-2017-0151-0018>.

<sup>29</sup> See *id.* at 43-44.

<sup>30</sup> See Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. 36,861 (July 31, 2018).

today and risk forgoing better opportunities to leverage modern technologies and practices to enhance pipeline safety. The Associations estimate that approximately 185 class location change pipe replacements occur annually.<sup>31</sup> Most of these replacements involve changes from a class 1 to 3 location, so most of the involved pipe will not meet the class 3 valve spacing requirements in § 192.179(a). Because the vast majority of class change pipe replacements are less than two miles in length, it appears that proposed § 192.610 would now require the installation of at least one manual valve for many class 1 to class 3 replacements. The Associations estimate that it costs \$600,000 – \$800,000 to install a new manual valve on an existing 24” – 36” pipeline.<sup>32</sup> Therefore, with 185 class change replacements per year, the cost of new § 192.610 could exceed \$100 million per year.

Allocating \$100 million per year to manual valve installations on 75 miles of pipe would reduce the resources available to pursue more advanced technologies and practices that improve the safety of the entire pipeline system. For example, for \$100 million, instead of installing manual valves on 75 miles of pipe, operators could assess over 10,000 miles with in-line inspection,<sup>33</sup> install launchers and receivers to enable over 2,000 miles of pipeline to be assessed with in-line inspection tools for the first time,<sup>34</sup> or conduct over 1,600 anomaly evaluation digs.<sup>35</sup>

The Associations note that PHMSA has not yet accounted for the full economic impacts of complying with § 192.610 in the current rulemaking proceeding, particularly with respect to the costs and benefits of installing new manual valves for short class location pipe replacements. The Pipeline Safety Act requires PHMSA to conduct a risk assessment for each proposed safety standard that it issues and to consider the “reasonably identifiable or estimated” benefits and costs expected to result from implementation or compliance with that standard as part of the assessment.<sup>36</sup> PHMSA may not propose a standard for adoption without making a “reasoned determination that the benefits of the intended standard justify its costs.”<sup>37</sup>

There is no indication in the record that PHMSA considered the full costs of complying with § 192.610 before issuing the Proposed Rule, which effectively applies the new construction valve spacing

---

<sup>31</sup> See Comments of AGA, APGA, API and INGAA on Class Location Change Requirements at 44, No. PHMSA-2017-0151 (Oct. 1, 2018), <https://www.regulations.gov/document?D=PHMSA-2017-0151-0018>. The Associations collected data from operators representing over 160,000 miles of gas transmission pipelines. The data from those operators indicated an average of 105 replacements per year. Extrapolating this data for the approximately 300,000 miles of gas transmission pipelines nation-wide yields approximately 185 class location change pipe replacements per year.

<sup>32</sup> See Comments of AGA, APGA, API and INGAA on Notice of Review of Guidance at 8, No. DOT-OST-2017-0069 (May 8, 2019), <https://www.regulations.gov/document?D=DOT-OST-2017-0069-2896>.

<sup>33</sup> Although in-line inspection costs will vary substantially based on the type of tool and other operational factors, data from the Associations’ member survey indicates an average cost of \$10,000 per mile for in-line inspection.

<sup>34</sup> Although the costs of installing launchers and receivers will vary significantly based on pipeline-specific factors, data from the Associations’ member survey indicates an average cost of \$1.8 million to install a mid-diameter (16-24 in.) launcher and receiver set.

<sup>35</sup> Although the costs of an anomaly evaluation dig will vary substantially based on the specific circumstances of the excavation, data from the Associations’ member survey indicates an average cost of \$62,500 to conduct an anomaly evaluation dig.

<sup>36</sup> 49 U.S.C. § 60102(b)(2)(D-E) (2018).

<sup>37</sup> *Id.* at § 60102(b)(5).

requirements to all class location pipe replacements. In fact, the rulemaking history, as described in further detail above in Section III.D, strongly suggests that PHMSA has never given serious consideration to the impacts associated with applying design and construction requirements to operations and maintenance (O&M) replacements<sup>38</sup> in the five decades since the creation of the federal pipeline safety program. This rulemaking is the first time that PHMSA is formally proposing industry-wide requirements for valve spacing related to O&M replacement projects. Below, the Associations suggest modifications to proposed § 192.610 that would allow for a more effective and efficient approach to managing the safety of class location changes through valve automation and installation.

***B. PHMSA should revise proposed § 192.610 to allow operators to automate existing valves instead of installing new valves when class location changes occur.***

When a class change pipe replacement occurs on a segment that does not conform to the valve spacing requirements of §192.179(a) for the new class location, PHMSA should allow operators to automate existing valves as an alternative to installing new valves. The Proposed Rule should embrace opportunities to promote modern automated valve technology. For class change pipe replacements that involve less than two contiguous miles of pipe, PHMSA should provide operators the option to automate an existing upstream and downstream valve such that the distance between rupture-mitigation valves for each shut-off segment does not exceed 20 miles (the class 1 valve spacing). This is consistent with the approach that PHMSA has proposed for replacements greater than or equal to two contiguous miles in class 1 and 2 locations that are also HCAs. Retaining the class 1 valve spacing is appropriate for class change pipe replacements that do not meet the two-mile “entirely replaced” definition and will mitigate the need to install a new valve for most class change replacements.

There are numerous advantages to allowing automation of existing manual valves rather than installation of new manual valves. First, this will provide automated rupture protection for both the class change segment and the rest of the 20-mile shut-off segment. As PHMSA notes in the preamble to the Proposed Rule, automated valves often allow for a faster emergency response than manual valves. Second, this approach is forward-looking. The Proposed Rule will likely lead to improvements in rupture detection technology across the industry in the coming years. Installing automated valves today positions pipeline operators to leverage future improvements in rupture detection technology. Third, the resources required to automate existing valves are much more reasonable than to install a new valve at each class change pipe replacement. The Associations estimate that the average cost of automating an existing valve is \$150,000–\$300,000.<sup>39</sup> Applied to 185 segments, this lowers the cost estimate for proposed § 192.610 to \$28–\$56 million per year, down from \$100+ million as currently proposed.

***C. PHMSA should exclude short pipe replacements from § 192.610.***

PHMSA should exclude replacements that are less than 2,000 contiguous feet from § 192.610. From a cost and planning perspective, these short pipe replacements are much more akin to routine maintenance than new construction. Furthermore, a short replacement could occur as part of a pressure test in accordance with § 192.611(a)(3), where the rest of the class location change segment is

---

<sup>38</sup> As clarified in PI-02-0101, an O&M replacement is “not new construction because it is designed to maintain the serviceability of an existing service line.”

<sup>39</sup> Based on a survey of operators representing more than 120,000 miles of gas transmission pipelines.



being pressure tested, not replaced, to comply with § 192.611. Attaching a valve requirement to such short replacements risks making this run-of-the-mill work impracticable. As noted previously, the cost to install a new manual valve ranges from \$600,000 – \$800,000. This could easily exceed the cost of a pipe replacement of less than 2,000 feet. Furthermore, when an operator is only removing a short section of pipe, there may not be an appropriate location in that short area to install a new valve, which would require the operator to execute an additional project on another portion of the pipeline, potentially extending pipeline downtime and community impacts.

PHMSA has issued two enforcement cases directing operators to install valves where pipe has been replaced due to a class location change. In 1998, almost three decades after the adoption of Part 192, PHMSA issued the *Viking* enforcement case and applied the design and construction requirements related to valve spacing to a class location change pipe replacement.<sup>40</sup> In 2015, PHMSA issued a decision in another enforcement case, *In the Matter of Williams Northwest Pipeline, LLC*, and determined that an operator did not add a valve to maintain the spacing required after a class location change pipe replacement.<sup>41</sup> PHMSA did not assess whether safety would be improved by adding additional valves to a short replacement sections in either of these cases. Nor did PHMSA consider the costs of applying the design requirements to short replacements of pipe. The Associations suggest that setting the threshold at 2,000 contiguous feet appropriately balances the safety benefit obtained by installing new valves against the need to avoid placing an overwhelming burden on small replacement projects.

#### ***D. Suggested revisions to proposed rule***

To achieve the objectives outlined above, the Associations recommend the additions to proposed § 192.610 that are shown **in red** below:

#### **§ 192.610 Change in class location: change in valve spacing.**

- (a) If a class location change on a transmission line occurs after **[EFFECTIVE DATE OF FINAL RULE]** and results in pipe replacement **of two or more contiguous miles** to meet the maximum allowable operating pressure requirements in §§ 192.611, 192.619, or 192.620, then the requirements in §§ 192.179 and 192.634, **as appropriate**, apply to the new class location, and the operator must install valves as necessary to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with § 192.611(d).
- (b) If a class location change on a transmission line occurs after [EFFECTIVE DATE OF FINAL RULE] and results in pipe replacement of less than two contiguous miles to meet the maximum allowable operating pressure 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 spacing requirements of § 192.179(a) for the replaced segment; or**
  - (2) Install or use existing rupture-mitigation valves so that the entirety of the replaced segment is between at least two rupture-mitigation valves. The distance between rupture-mitigation valves for the replaced segment must not exceed 20 miles. The rupture-mitigation valves must comply with all requirements of § 192.634(c)-(f).**

---

<sup>40</sup> *In the Matter of Viking Gas Transmission*, CPF No. 32102 (Apr. 27, 1998).

<sup>41</sup> *In the Matter of Williams Northwest Pipeline, LLC*, CPF No. 5-2014-1002 (Dec. 29, 2015).

**(c) This section does not apply to pipe replacements that are less than 2,000 contiguous feet.**

V. PHMSA Should Revise the Proposed Automated Valve Performance Standards to Avoid Unnecessary Service Disruptions and Accommodate the Full Breadth of Gas Transmission Pipeline Operations Scenarios

***A. PHMSA should eliminate the ten-minute “identification” requirement because the 40-minute response standard is sufficient to ensure safety in class 3, 4, and HCA locations.***

The requirement to identify ruptures within ten minutes of notification is unnecessary for safety, impracticable, and risks significant service disruptions for natural gas customers. PHMSA should eliminate the ten-minute identification requirement because the 40-minute response standard is sufficient to ensure safety in class 3, 4, and HCA locations. PHMSA’s regulations should focus on the desired safety outcome—isolation as soon as practicable following rupture identification. It is unnecessary and inappropriate for PHMSA to prescriptively regulate the intermediate decision-making steps.

The decision to shut down a pipeline has serious implications and should not be rushed to meet an arbitrary ten-minute threshold. When gas service is shut off, manufacturing facilities may have to stop operating, power generation plants may not be able to generate electricity, small businesses may have to close their doors, and everyday Americans may lose the ability to heat their homes and cook their food. Furthermore, if the shutdown requires the operator to re-light appliance pilot lights before resuming service, consumers could be without natural gas for days or longer.

Operators should be provided the necessary time to determine whether a pipeline needs to be shut down. Many steps may be involved in the decision to shut down a pipeline, which renders a ten-minute across-the-board threshold inappropriate. In areas with multiple pipelines, operators will need to coordinate with emergency responders and each other to determine the source of the rupture. Also, following a potential rupture event, an operator may need to process conflicting information from different sources. Callers reporting a potential rupture often are not able to report an accurate location. Finally, where operator personnel are stationed nearby a potential rupture location, it may be appropriate to direct those personnel to travel to the potential rupture location before shutting down the pipeline, which would likely take more than ten minutes but often less than 40.

Furthermore, PHMSA’s proposed rupture definition, specifically paragraph 3, is intentionally broad—the proposed rupture definition includes a change that “may be representative” of a rupture. The Associations do not object to this broad language because it reflects the fact that it is often not clear whether a rupture has occurred until an operator investigates further. Nevertheless, this language in § 192.3 and the practical uncertainty following potential ruptures supports eliminating the ten-minute identification requirement.

***B. PHMSA should require operators to establish specific rupture notification criteria for each pipeline, rather than applying the same pressure drop criterion to all pipelines.***

PHMSA should require operators to define criteria in their operating procedures that are indicative of a potential rupture for each pipeline, such as a specific pressure drop rate, rather than defining “rupture” for all pipelines as a drop of 10 percent or greater over a 15-minute interval. The proposed definition of “rupture” does not take into account that operators’ natural gas systems and their customers’ needs are

unique and dynamic. The proposed definition arbitrarily establishes setpoints which require response and potentially isolating the gas pipeline system. PHMSA did not provide a basis for the 10 percent over 15 minutes threshold in the NPRM. In fact, PHMSA's proposal equates to a 0.67% drop per minute, which is smaller than the minimum rate-of-change monitoring capabilities for many pneumatic-controlled automatic shutoff valves that are in service today. However, PHMSA has not provided any indication that existing automatic shutoff valves are not functioning appropriately today.

Changes in pressure may occur due to demand or increases in customer load requirements, seasonal cycling, and opening of crossover piping. By unnecessarily triggering rupture response, PHMSA's proposed 10 percent over 15 minutes criteria may potentially compromise the reliability of service to customers, including residential, agricultural, and business users of gas, electric generators, and manufacturers. Based on the size of the isolated service area, the time required to relight customers' appliances could be substantial and costly. Rather than prescribe a one-size-fits-all rupture criteria, the Associations recommend that PHMSA direct operators to establish rupture notification criteria for their individual operating systems and to clearly outline these criteria within each operator's procedures.

***C. PHMSA should distinguish "notification of potential rupture" from "rupture identification" in § 192.3.***

In the Proposed Rule, PHMSA proposes a new definition for "rupture" in § 192.3. However, PHMSA's proposed definition does not address actual ruptures—it addresses notification of potential ruptures. Therefore, PHMSA should re-label this definition "notification of potential rupture." In addition to being more accurate, this change will help distinguish this new definition from the "rupture" definition in PHMSA's incident reporting form instructions.<sup>42</sup>

This change will also provide much needed clarity with respect to other sections of the proposed rule—specifically, §§ 192.615(a)(6) and 192.935(c)(1)—that refer to "rupture identification," which is separate from notification of a potential rupture. Rupture identification is a determination that the operator makes subsequent to notification of a potential rupture.

PHMSA should also revise proposed paragraph (1) of the rupture definition. It is unnecessary to list who might observe or report a potential rupture to the operator. Any report of a potential rupture will be taken seriously.

***D. PHMSA should limit the definition of "notification of potential rupture" to gas transmission pipelines.***

PHMSA should explicitly limit the definition of "notification of potential rupture" in § 192.3 to only apply to gas transmission lines. This enables 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.

---

<sup>42</sup> PHMSA, Instructions for Form F7100.2-1, Incident Report—Gas Transmission and Gathering Systems at 19 (rev. Apr. 2019), <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/subdoc/3971/currentgtggincidentinstructionsphmsa-f-710022019-04-and-beyond.pdf>.

***E. PHMSA should allow operators to liaise with appropriate local emergency coordinating entities as a means to communicate with first responders.***

It is not practicable for pipeline operators to maintain communications with and know the response capabilities of every individual emergency response entity within its footprint at a given moment in time. Even smaller operators could have thousands of first responder entities within their footprint, the majority of which are usually volunteer organizations with limited capacity to individually and separately engage with each pipeline company in their jurisdiction.

Rather than overwhelm operators and first responders with individual engagement requirements, PHMSA should allow operators to liaise with the appropriate local emergency coordinating entities—such as county emergency managers, local emergency planning committees (LEPCs), or 9-1-1 agencies—who are better equipped to coordinate emergency response and are familiar with the capabilities of each agency in their jurisdiction. This approach would be consistent with the Pipeline Emergency Responder Initiatives (PERIs) that have been developed in several states with the support of PHMSA.

***F. PHMSA should limit § 192.615(a)(2) to emergency preparedness activities and § 192.615(a)(8) to emergency response activities.***

As currently drafted, §§ 192.615(a)(2) and § 192.615(a)(8) create confusion because they both address liaison requirements with emergency responders to prepare for a potential future emergency. But § 192.615(a)(8) also addresses post-emergency response, and it is unclear which requirements in 192.615(a)(8) apply pre- and post-emergency. PHMSA should limit § 192.615(a)(2) to emergency preparedness activities and § 192.615(a)(8) to emergency response activities so that both sets of requirements are clear.

***G. The Associations support PHMSA requiring distribution pipeline operators to liaise with and notify public safety answering points.***

While the preamble and the PRIA indicate that the Proposed Rule was only apply to natural gas transmission and hazardous liquid pipelines, the Associations support including public safety answering points (9-1-1 emergency call centers) as a stakeholder in distribution operators' Emergency Plans, per proposed §§ 192.615(a)(2), 192.615(a)(8), 192.615(c).

***H. Suggested revisions to proposed rule***

To achieve the objectives outlined above, the Associations recommend the modifications to proposed §§ 192.3 and 192.615 that are shown **in red** below:

**§192.3 Definitions.**

[ . . . ]

***Notification of Potential Rupture*** means any of the following events that involve an **unintentional and** uncontrolled release of a large volume of gas **from a transmission pipeline**:

- (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 **meeting defined in** paragraphs (2) or (3) of this definition **is observed by or reported to the operator**;
- (2) **The operator observes** an unanticipated or unplanned pressure loss **outside of the pipeline's normal**

~~operating parameters, as defined in the operator's procedures, 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) **The operator observes** an unexplained flow rate change, pressure change, instrumentation indication, or equipment function that may be representative of an event **meeting defined in** paragraph (2) of this definition.

Note: ~~Rupture identification~~ **Notification** occurs when a rupture, as defined in this section, is first observed by or reported to pipeline operating personnel or a controller.

[...]

### **§192.615 Emergency plans.**

- (a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

[...]

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

[...]

- (6) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, and pressure reduction, in any section of the operator's pipeline system necessary to minimize hazards of released gas to life, property or the environment. Each operator installing valves in accordance with § 192.179(e) or subject to the requirements in § 192.634 must also evaluate and identify a **notification of potential** rupture as defined in § 192.3 as being an actual rupture event or non-rupture event in accordance with operating procedures as soon as practicable **following but within 10 minutes of** the initial notification to or by the operator, regardless of how the rupture is initially detected or observed.

[...]

- (8) ~~Notifying the appropriate public safety answering point (9-1-1 emergency call center), as well as fire, police, and other public officials of gas pipeline emergencies to coordinate and share information to determine the location of the release, including both planned responses and actual responses during an emergency. The operator (pipeline controller or the appropriate operator emergency response coordinator) must~~ Immediately and directly **notifying** the appropriate public safety answering point (9-1-1 emergency call center) or other coordinating agency for the communities and jurisdictions in which the pipeline is located after the operator determines a rupture has occurred when a release is indicated and rupture-mitigation valve closure is implemented **to coordinate and share information to determine the location of the release.**

[...]

## VI. PHMSA Should Modify § 192.634(b) to Allow the Use of Additional Technologies and Practices

### ***A. Operators should be permitted to use a locked manual valve as a rupture mitigation valve on crossovers.***

PHMSA should revise proposed § 192.634(b) to permit operators to use a “locked-out, tagged-out” manual valve as a rupture mitigation valve on crossover piping. If a manual valve is locked-out and tagged-out during normal operations, it will already be closed during any rupture event, and therefore no valve automation is needed. This allowance would provide significant resource savings without compromising pipeline safety—while the average cost to automate an existing crossover valve is \$150,000–\$300,000,<sup>43</sup> the cost to lock the valve is effectively zero. This approach would apply the same level of safety to crossovers as new service lines not in use under § 192.379 and abandoned facilities under § 192.727.

### ***B. Operators should be permitted to use check valves to protect laterals in certain scenarios.***

In proposed § 192.634(b), PHMSA prescribes requirements for laterals for the purposes of protecting the mainline piping. However, a two-plus-mile replacement or new construction of a lateral itself could also require rupture mitigation under § 192.634(b). PHMSA should permit operators to use a check valve as a rupture mitigation valve for a lateral, provided that the check valve is positioned to stop flow into the shut-off segment (the new/replaced lateral).

For example, an operator may replace 2.5 miles of a transmission lateral in a class 3 area that feeds a mainline transmission pipeline. In the event of a rupture, flow could be mitigated with an upstream automated shutoff valve and a downstream check valve on the lateral—the downstream check valve would stop flow into the lateral from the mainline piping.

### ***C. PHMSA should clarify that remote monitoring of automated valve status is not required.***

Section 192.634(f)(3) appears to allow operators to use locally-actuated automatic shutoff valves that do not have remote monitoring of valve position. PHMSA should add language to § 192.634(f)(3) to confirm that locally-actuated automatic shutoff valves are acceptable. The Associations recommend that when an operator is using a locally-actuated automatic shutoff valve, PHMSA should require the operator to have the capability to monitor pressures or gas flow rates on the pipeline in order to identify and locate a rupture.

Remotely-monitoring valve position requires operators to run communications and power equipment to the automated shutoff valve. This may be impracticable or very resource-intensive in remote areas far from existing communications and power infrastructure or in highly dense areas where there is limited space to add new equipment. A locally-actuated automated valve would provide a significantly faster response than a manual valve for most scenarios. The Associations estimate that the average cost of installing a new valve with remote position monitoring is \$450,000 to \$950,000, based on valve size, versus \$300,000 to \$750,000 without the remote monitoring. The Associations estimate that the cost of automating an existing valve with remote position monitoring is \$200,000 to \$300,000, versus \$150,000 to \$200,000 without the remote monitoring.<sup>44</sup>

---

<sup>43</sup> Based on a survey of operators representing more than 120,000 miles of gas transmission pipelines.

<sup>44</sup> Based on a survey of operators representing more than 120,000 miles of gas transmission pipelines.

***D. Where valve status is not available, PHMSA should permit operators to monitor pressures or gas flow rates—it is unnecessary to monitor both.***

Monitoring either pipeline pressures or flow rates will indicate if and where a rupture has occurred. Pressure sensors are much more prevalent on most pipelines than flow meters, so many pipeline locations already have pressure monitoring but may not have flow monitoring. PHMSA should allow operators to use either method to monitor for ruptures when the operator is using a manual or locally-actuated valve. Otherwise, operators may be required to install unnecessary and potentially duplicative flow meters at every location of a manual or locally-actuated rupture-mitigation valve.

***E. PHMSA should allow operators to leave rupture-mitigation valves open during certain rupture scenarios.***

PHMSA should provide an allowance in § 192.634(c) and (e) for scenarios where the operator and emergency responder agree not to shut a rupture-mitigation valve following a rupture. There are scenarios where intentionally leaving a valve open is a safe and effective means of removing gas from a ruptured pipeline. For example, if a rupture occurs in a densely-populated area, allowing the downstream rupture-mitigation valve to remain open would allow gas to continue moving through the pipeline and reduce the amount of gas escaping at the rupture location.

Similarly, if a rupture occurs in a remote location, operators and first responders may agree that it is unnecessary to close an upstream automated valve due to impacts on critical customers (for example, hospitals, power plants, etc.).

***F. PHMSA should clarify that the rupture-mitigation valve need not be the nearest valve to the shutoff segment.***

PHMSA should clarify in § 192.634(b) that the operator can select any mainline or station valve as the rupture-mitigation valve as long as the shut-off segment length complies with the spacing requirements for class 3, 4, or HCA locations, as applicable. Operators should be able to maximize the area protected by rupture-mitigation valves even where a segment has closely-spaced manual valves (for example, a river crossing).

***G. PHMSA should clarify that no downstream rupture-mitigation valve is required at the termination of a pipeline.***

PHMSA should clarify in § 192.634(b) that no downstream rupture-mitigation valve is required at the termination of a transmission line if the upstream valve provides the spacing required under § 192.634(b). For example, if there is an upstream rupture-mitigation valve less than fifteen miles from a transmission pipeline's termination at a gate station in a class 3 location, then no rupture-mitigation valve should be required at the termination/gate station.

***H. PHMSA should explicitly state in § 192.634(b) that the shut-off segment must contain the new or replaced class 3, 4, or HCA segment.***

Although § 192.634(a) is clearly limited to new and replaced pipe in class 3, 4, and HCA locations, the definition of "shut-off segment" in § 192.634(b) is not currently tied to the new or replaced pipe. PHMSA should revise § 192.634(b) to make that connection clear.

**I. PHMSA should reduce duplication and repetition of requirements in § 192.634(b).**

The Associations recommend that PHMSA remove certain sections from proposed § 192.634(b) that appear to be duplicative. When similar requirements are repeated more than once in PHMSA's regulations, it can create confusion about whether the duplicative requirement actually represents an additional requirement. Furthermore, duplicative requirements make it more challenging to update and understand PHMSA's code as it evolves over time. When PHMSA's code language is clear, there is no need to restate the same requirement more than once.

The Associations recommend the following changes:

- PHMSA should define "shut-off segment" once at the beginning of § 192.634(b). The Associations believe it is unnecessary and potentially confusing to define "shut-off segment" three times in proposed § 192.634(b).
- PHMSA should remove § 192.634(c) and (f)(4). These sections seem to address the same rupture-mitigation performance requirements as § 192.634(e).
- PHMSA should remove § 192.634(f)(5), which appears to repeat similar requirements as § 192.634(f)(1)-(3).
- As noted previously, the Associations suggest relocating proposed § 192.634(g) to § 192.179.

**J. Suggested revisions to proposed rule**

To achieve the objectives outlined above, the Associations recommend the modifications to proposed § 192.634(b)-(f) that are shown **in red** below:

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

[ . . . ]

(b) *Maximum spacing between valves.* Rupture-mitigation valves must be installed in accordance with the following requirements:

- (1) **Shut-off Segment. For purposes of this subsection, "shut-off segment" means the segment of pipe located between the upstream mainline valve closest to the upstream endpoint of the new or replaced Class 3 or 4 or high consequence area segment and the downstream mainline valve closest to the downstream endpoint of the new or replaced Class 3 or 4 or high consequence area segment. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline 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 gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or 4 locations or high consequence area segments may be contained within a single shut-off segment.**
- (2) **Rupture-Mitigation Valves. Valves needed to isolate the entire shut-off segment in accordance with the spacing requirements of this subsection are "rupture-mitigation valves." The operator is not required to select the closest valve to the shutoff segment as the rupture-mitigation valve. The operator may use a station valve as a rupture-mitigation valve. A downstream rupture-mitigation valve is not required where the distance between the end of the transmission line and the upstream rupture-mitigation valve complies with the spacing requirements in this subsection.**
- (3) **High Consequence Areas. For purposes of this paragraph (b)(1), "shut off segment" means the segment of pipe located between the upstream mainline valve closest to the upstream high consequence area segment endpoint and the downstream mainline valve closest to the**



~~downstream high consequence area segment endpoint so that the entirety of the high consequence area segment is between at least two rupture mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, then the segment also extends to the nearest 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). All such valves on a shut-off segment are "rupture mitigation valves."~~ Multiple high consequence areas may be contained within a single shut-off segment. The distance between rupture-mitigation valves for each shut-off segment **containing a high consequence area** must not exceed:

- (i) 8 miles if one or more high consequence areas in the shutoff segment is in a Class 4 location;
  - (ii) 15 miles if one or more high consequence areas in the shutoff segment is in a Class 3 location, and
  - (iii) 20 miles if all high consequence areas in the shutoff segment are located in Class 1 or 2 locations, or
  - (iv) The mainline valve spacing requirements of § 192.179 when mainline valve spacing does not meet § 192.634(b)(~~31~~)(i), (ii), or (iii).
- (4) ~~Class 3 locations. For purposes of this paragraph, "shut-off segment" means the segment of pipe located between the upstream mainline valve closest to the upstream endpoint of the Class 3 location and the downstream mainline valve closest to the downstream endpoint of the Class 3 location so that the entirety of the Class 3 location is between at least two rupture mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, the shut-off segment also extends to the nearest 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). All such valves on a shut-off segment are "rupture mitigation valves."~~ Multiple Class 3 locations may be contained ~~within a single shut-off segment.~~ The distance between mainline valves serving as rupture-mitigation valves for each shut-off segment **containing a class 3 location** must not exceed 15 miles.
- (5) ~~Class 4 locations. For purposes of this paragraph, "shut-off segment" means the segment of pipe between the upstream mainline valve closest to the upstream endpoint of the Class 4 location and the downstream mainline valve closest to the downstream endpoint of the Class 4 location so that the entirety of the Class 4 location is between at least two rupture mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, the shut-off segment also extends to the nearest 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). All such valves on a shut-off segment are "rupture mitigation valves."~~ Multiple Class 4 locations may be contained ~~within a single shut-off segment.~~ The distance between mainline valves serving as rupture-mitigation valves for each shut-off segment **containing a class 4 location** must not exceed 8 miles.
- (6) *Laterals.* Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have rupture-mitigation valves that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of these 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 constructed or where 2 or more**

contiguous miles have been replaced after [DATE 24 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE], a check valve may be used as a rupture-mitigation valve where it is positioned to stop flow into the lateral. Check valves used as rupture-mitigation valves in accordance with this paragraph are not subject to subsections (c)-(f).

- (7) Crossovers. An operator may use a manual valve as a rupture mitigation valve for a crossover connection if during normal operations the valve is closed to prevent the flow of gas 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 locked in accordance with the operator's lock-out and tag-out procedures.

~~(c) Valve shut-off time for rupture mitigation. Upon identifying a rupture, the operator must, as soon as practicable:~~

- ~~(1) Commence shut-off of the rupture mitigation valve or valves which would have the greatest effect on minimizing the release volume and other potential safety and environmental consequences of the discharge to achieve full rupture mitigation valve shut-off within 40 minutes of rupture identification; and~~  
~~(2) Initiate other mitigative actions appropriate for the situation to minimize the release volume and potential adverse consequences.~~

(c) *Valve shut-off capability.* Onshore transmission line rupture-mitigation valves must have actuation capability (i.e., remote-control shut-off, automatic shut-off, equivalent technology, or manual shut-off where personnel are in proximity) to ensure pipeline ruptures are promptly mitigated based upon maximum valve shut-off times, location, and spacing specified in paragraphs (b) and ~~(d)~~ (e) of this section to mitigate the volume and consequence of gas released.

(d) *Valve shut-off methods.* All onshore transmission line rupture-mitigation valves must be actuated by one of the following methods to mitigate a rupture as soon as practicable but within 40 minutes of rupture identification:

- (1) Remote control from a location that is continuously staffed with personnel trained in rupture response to provide immediate shut-off following identification of a rupture or other decision to close the valve;
- (2) Automatic shut-off following identification of a rupture; or
- (3) Alternative equivalent technology that is capable of mitigating a rupture in accordance with this section.
- (4) *Manual operation upon identification of a rupture.* Operators using a manual valve in accordance with § 192.179(e), must appropriately station personnel to ensure valve shut-off in accordance with ~~paragraph (c) of~~ this section. 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 40-minute total response time in ~~paragraph (c)(1) of~~ this section.

- (5) **Open Valves. An operator may leave a rupture-mitigation valve open for more than 40 minutes following rupture identification if the operator, in coordination with appropriate local responders and public authorities, determines that is safe to leave the valve open.**

(e) *Valve monitoring and operation capabilities.* Onshore transmission line rupture- mitigation valves actuated by methods in paragraph ~~(d)~~ (e) of this section must be capable of being:

- (1) Monitored or controlled by either remote or onsite personnel;
- (2) Operated during normal, abnormal, and emergency operating conditions; and
- (3) Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. For automatic shut-off valves, valve status need not be monitored remotely if the operator has the capability to monitor pressures or gas flow rates on the

**pipeline to be able to identify and locate a rupture.** Pipeline segments that use manual valve operation must have the capability to monitor pressures **and or** gas flow rates on the pipeline to be able to identify and locate a rupture.

- ~~(4) Initiated to close as soon as practicable after identifying a rupture and with complete valve shut-off within 40 minutes of rupture identification as specified in paragraph (c) of this section; and~~
- ~~(5) Monitored and controlled by remote personnel or must have a back-up power source to maintain SCADA or other remote communications for remote control shut-off valve or automatic shut-off valve operational status.~~

(f) *Monitoring of valve shut-off response status.* Operating control personnel must continually monitor rupture-mitigation valve position and operational status of all rupture-mitigation valves for the affected shut-off segment during and after a rupture event until the pipeline segment is isolated. Such monitoring must be maintained through continual electronic communications with remote instrumentation or through continual verbal communication with onsite personnel stationed at each rupture-mitigation valve, via telephone, radio, or equivalent means.

~~(g) *Alternative equivalent technology or manual valves for onshore transmission rupture mitigation.* If an operator elects to use alternative equivalent technology or manual valves in accordance with § 192.179(e), the operator must notify PHMSA at least 90 days in advance of installation or use in accordance with § 192.949. The operator must include a technical and safety evaluation in its notice to PHMSA, including design, construction, and operating procedures for the alternative equivalent technology or manual valve. Operators installing manual valves must also demonstrate that installing an automatic shutoff valve, a remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. An operator may proceed to use the alternative equivalent technology or manual valves 91 days after submitting the notification unless it receives a letter from the Associate Administrator of Pipeline Safety informing the operator that PHMSA objects to the proposed use of the alternative equivalent technology or manual valves or that PHMSA requires additional time to conduct its review.~~

## VII. PHMSA Should Reconsider the Proposed Maintenance Requirements for when a Rupture-Mitigation Valve is Unable to Achieve the Performance Standard and Clarify the Proposed Drill Requirements

### ***A. PHMSA should allow twelve months to repair, replace, or install new automated valves.***

Proposed §§ 192.745(d)-(e) requires operators to repair, replace, or install new automated valves within six months if an automated valve is not operating correctly or if a drill indicates that a manual or locally-automated valve cannot achieve the 40-minute response time requirements. As noted previously, lead times for larger-diameter valves can be up to one year, and valve operators for older valves will require special designs and custom equipment that often have long lead times. Acquiring necessary permits, access to commercial power, and potential communications network connections may also be an extended effort. Therefore, PHMSA should allow twelve months to repair, replace, or install new automated valves when an automated valve is not operating correctly or a drill indicates that a manual or locally-automated valve cannot achieve the 40-minute response time requirements.

### ***B. When a rupture-mitigation valve requires maintenance, operators should designate an alternative “shut-off valve” and document an interim response plan.***

Proposed § 192.745(e)(2) would require operators to designate an alternate “compliant” valve when a rupture-mitigation valve requires maintenance or replacement. It is unclear what “compliant” means in this context. Section 192.745(e)(2) should instead direct operators to designate an alternative “shut-

off" valve and document an interim response plan until the primary rupture-mitigation valve is repaired or replaced.

Unless an operator has installed redundant automated valves, it is unlikely that an operator will have another automated valve available that complies with all of the spacing, instrumentation, and performance requirements of §§ 192.719 and 192.634. Likewise, existing manual valves may not be able to achieve the proposed 40-minute response requirement. It is unreasonable to require operators to have multiple, duplicative "compliant" valves that can achieve the requirements of the Proposed Rule for the unlikely event that a rupture-mitigation valve requires extended repairs or needs to be replaced. This could require an operator to install four rupture-mitigation valves around each new shutoff segment, which would require operators to install new valves for many two-plus-mile replacement projects. As noted previously, PHMSA's PRIA does not account for the addition of any new valves, and the resources required to automate existing valves are much more reasonable than those required to install a new valve during each pipe replacement.

PHMSA should also clarify that automated valves must be able to maintain "effective" shut-off. Complete bubble-tight shut-off is not needed to mitigate the effects of a rupture.

***C. When a drill indicates that a rupture-mitigation valve does not meet the performance requirements, operators will need up to twelve months to implement alternative measures.***

For similar reasons as in the previous section, PHMSA should remove the references to § 192.745(e) and "alternative measures" from proposed § 192.745(d)(3). Even if a drill demonstrates that total response time exceeds 40 minutes, it is unlikely that there is an alternative valve that can be closed more quickly, unless that operator has installed duplicative valves. An operator will often need up to twelve months to install a new valve or automate existing valves to comply with the § 192.634 performance requirements following a failed drill.

***D. PHMSA should allow a notification process where repairing or replacing a rupture mitigation valve within twelve months is not practicable.***

Operators intend to repair or replace any rupture mitigation valve that is found to be inoperable as soon as practicable, per § 192.745(e). However, delays may occur which exceed the proposed twelve-month window proposed by the Associations. For large diameter valves or customized equipment, lead times may approach or exceed one year, and this does not account for the time required to actually install the new equipment. Additionally, the repair or replacement timeline could be limited by weather constraints that could prevent safe valve installation, operational constraints that may not allow for the system to be taken out of service, or potential permitting delays. Therefore, the Associations recommend that PHMSA revise § 192.745(e) to include a notification process by which operators can alert PHMSA of potential delays in meeting the twelve-month timeline.

***E. PHMSA should clarify that annual drills are not required for every manual valve.***

PHMSA should clarify that the annual drill requirements specified under § 192.745(d)(2) are not required for all manual or locally-operated valves. The Associations believe that PHMSA's intent is to have operators perform periodic drills on a sample of manual or locally-operated valves, as defined within § 192.745(d)(2). The Associations recommend that PHMSA remove the word "each" from § 192.745(d) to clarify.

**F. PHMSA should clarify that operators are required to drill based on “reasonable” worst-case scenarios.**

PHMSA should clarify in § 192.745(d)(2) that operators are required to conduct drills that simulate “reasonable” worst-case scenarios (for example, pipeline emergency response during poor weather that is reasonably foreseeable for the location). Operators should not be required to simulate extreme scenarios—for example, pipeline emergency response during an act of war by a foreign nation.

**G. PHMSA should clarify that the requirement to conduct drills for “locally-actuated” valves excludes automatic valves.**

From a technical perspective, automatic shutoff valves are locally-actuated. The Associations believe that PHMSA’s proposed drill requirement for locally-actuated valves is intended to apply to non-automatic locally-actuated valves. It is not practicable to conduct a “drill” for an automatic shutoff valve— this would require the simulation of a rupture event on the pipeline system itself, which would affect pipeline operations. PHMSA should clarify that the requirement to conduct drills for “locally-actuated” valves excludes automatic valves.

**H. PHMSA should clarify that operators are not required to fully-close manual or locally-actuated valves during drills.**

Fully closing a valve during a drill could create significant unintended and negative consequences, such as the loss of gas to end use customers. PHMSA should clarify that the drills required under § 192.745(d) do not require full valve closure.

**I. PHMSA should remove § 192.745(c) because it is duplicative.**

Proposed § 192.745(c) appears to duplicate the point-to-point verification requirements of existing § 192.631(c). PHMSA should remove § 192.745(c). If PHMSA retains § 192.745(c), it should clarify that the point-to-point verification is required at the time of valve installation or initial automation, not on a recurring basis.

**J. Suggested revisions to proposed rule**

To achieve the objectives outlined above, the Associations recommend the modifications to proposed § 192.745(c)-(e) that are shown **in red** below:

**§ 192.745 Valve maintenance: Transmission lines.**

[ . . . ]

- ~~(c) For each valve installed under § 192.179(e) and each rupture mitigation valve under § 192.634 that is a remote control shut-off or automatic shut-off valve, or that is based on alternative equivalent technology, the operator must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with § 192.631(c) and (e).~~
- (c) For **each** rupture-mitigation valves under § 192.634 that **are is** manually or locally operated **(i.e., not automatic or remotely controlled)**:
  - (1) Operators must establish the 40-minute total response time as required by § 192.634 through an initial drill and through periodic validation as required in paragraph ~~(e)~~(2) of this section. Each phase of the drill response must be reviewed and the results documented to validate the

total response time, including valve shut-off, as being less than or equal to 40 minutes following rupture identification.

- (2) A mainline valve serving as a rupture-mitigation valve within each pipeline system and within each operating or maintenance field work unit must be randomly selected for an annual 40-minute total response time validation drill that simulates **reasonable** worst-case conditions for that location to ensure compliance. **Operators are not required to fully close the rupture-mitigation valve during the drill.** The response drill must occur at least once each calendar year, with intervals not to exceed 15 months.
- (3) If the 40-minute maximum response time cannot be validated or achieved in the drill, the operator must revise response efforts to achieve compliance with § 192.634 no later than **12 6** 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; and
  - (ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and
  - (iii) Any other areas identified by the operator as needing improvement.
- (d) Each operator must take remedial measures to correct any valve installed under § 192.179(e) or any rupture-mitigation valve identified in § 192.634 that is found 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 6** months after finding that the valve is inoperable or unable to maintain shut-off. **An operator must notify PHMSA in accordance with § 192.18 if a valve cannot be repaired or replaced within 12 months;** and
  - (2) Designate an alternative **shut-off compliant** valve within 7 calendar days of the finding while repairs are being made **and document an interim response plan.**

#### VIII. The Associations Recommend Changes to § 192.617 to Ensure Requirements are Clear

##### ***A. PHMSA should remove the reference to “failures” from § 192.617.***

The inclusion of the term “failure” in existing and proposed § 192.617 is unclear. “Failure” is not defined in Part 191 or Part 192. “Failure” is a broad term that can include abnormal operations that do not involve a gas release or a rupture. Incorporating lessons learned from abnormal operations into procedures is already required under § 192.605(c)(4). 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.

##### ***B. PHMSA should require operators to incorporate lessons learned and P&M measures following ruptures where appropriate and practicable.***

Proposed § 192.617(b)–(c) require operators to incorporate lessons learned and preventative and mitigative (P&M) measures into procedures following an incident investigation. The Associations support the incorporation of post-incident lessons learned as an important aspect of pipeline safety management systems. However, there may be some circumstances where an incident investigation does not yield a change to procedures (for example, some third-party damage incidents). Therefore, PHMSA should require operators to incorporate lessons learned and P&M measures “if appropriate and practicable” following an incident investigation.

##### ***C. PHMSA should clarify which incident investigation requirements apply to distribution lines.***

While the preamble and the PRIA indicate that the Proposed Rule only applies to natural gas transmission and hazardous liquid pipelines, the Associations support distribution operators incorporating post-incident lessons learned into their procedures per proposed § 192.617(b). The Associations recommend clarifying that the requirements in § 192.617(c) only apply to transmission lines. Due to PHMSA's proposed broad definition of "rupture" in § 192.3, § 192.617(c) could be interpreted to apply to both gas distribution and gas transmission pipeline incidents.

***D. PHMSA should remove proposed § 192.617(d) because it is duplicative.***

PHMSA should remove proposed § 192.617(d), which appears to duplicate documentation and recordkeeping requirements similar to those that are currently required under PHMSA's incident reporting requirements.

***E. Suggested revisions to the proposed rule***

To achieve the objectives outlined above, the Associations recommend the modifications to proposed § 192.617 that are shown **in red** below:

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

- (a) *Post-incident procedures.* Each operator must establish and follow post-incident 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, to determine the causes and contributing factors of the ~~failure or~~ incident and minimize the possibility of a recurrence.
- (b) *Post-incident lessons learned.* Each operator must develop, implement, and incorporate, **if appropriate and practicable**, lessons learned from a post-incident review into its procedures, including in pertinent operator personnel training and qualification programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.
- (c) *Analysis of rupture and valve shut-offs; preventive and mitigative measures.* If an ~~failure or~~ incident involves a rupture **of a gas transmission line as defined in § 192.3** or the closure of a rupture-mitigation valve as defined in § 192.634, the operator must also conduct a post-incident analysis of all factors impacting the release volume and the consequences of the release, and identify and implement, **if appropriate and practicable**, preventive and mitigative measures to reduce or limit the release volume and damage in 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:
  - (1) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the release ~~or failure event~~;
  - (2) Appropriateness and effectiveness of procedures and pipeline systems, including SCADA, communications, valve shut-off, and operator personnel;
  - (3) Actual response time from rupture detection to initiation of mitigative actions, and the appropriateness and effectiveness of the mitigative actions taken;
  - (4) Location and the timeliness of actuation of rupture-mitigation valves identified under § 192.634; and
  - (5) All other factors the operator deems appropriate.
- ~~(d) Rupture post incident summary. If a failure or incident involves a rupture as defined in § 192.3 or the closure of a rupture mitigation valve as defined in § 192.634, the operator must complete a summary of the post incident review required by paragraph (c) of this section within 90 days of~~



~~the failure or incident, and while the investigation is pending, conduct quarterly status reviews until completed. The post-incident summary and all other reviews and analyses produced under the requirements of this section must be reviewed, dated, and signed by the appropriate senior executive officer. The post-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.~~

IX. PHMSA Should Remove § 192.935(c)(1)-(2)

PHMSA should remove § 192.935(c)(1)-(2), which appear to simply restate the requirements of § 192.634. Section 192.634 already applies to HCAs. Proposed § 192.935(c)(3) does not appear duplicative and should be retained.

As noted previously, when similar requirements are repeated more than once in PHMSA's regulations, it can create confusion about whether the duplicative requirement is actually an additional requirement. Furthermore, duplicative requirements make it more challenging to update and understand PHMSA's code as it evolves over time. There is no need to restate the same requirement more than once.

PHMSA should also revise § 192.935(c) to clarify that automated valve installation decisions should consider the swiftness of rupture detection capabilities, not leak detection capabilities. Automated valve technology is designed to detect and close quickly following a rupture, which has a much different operational profile than a leak. Automated valves are appropriately designed to mitigate the severe consequences of a pipeline rupture, but are not appropriate to mitigate the consequences of smaller pipeline leaks. PHMSA's existing regulations requiring the periodic monitoring of leaks (§ 192.706) and the repair of hazardous leaks (§§ 192.703, 192.711, and 192.713) already address leaks.

**A. Suggested revisions to the proposed rule**

To achieve the objectives outlined above, the Associations recommend the modifications to proposed § 192.935(c) that are shown in red below:

**§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 an automatic shut-off valve (ASV) or remote-control valve (RCV) would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of rupture 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.

~~(1) Protection of onshore transmission high consequence areas from ruptures. An operator of an onshore transmission pipeline segment that is constructed, or that has 2 or more contiguous miles replaced, after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE] and is greater than or equal to 6 inches in nominal diameter and is located in a high consequence area must provide for the additional protection of those pipeline segments to assure the timely termination and mitigation of rupture events by complying with §§ 192.615(a)(6), 192.634, and 192.745. At a minimum, the analysis specified in paragraph (c) of this section must demonstrate that the operator can achieve the following standards for termination of rupture events:~~

~~(i) Operators must identify a rupture event as soon as practicable but within 10 minutes of the~~



- ~~initial notification to or by the operator, in accordance with § 192.615(a)(6), regardless of how the rupture is initially detected or observed;~~
- ~~(ii) Operators must begin closing shut-off segment rupture mitigation valves as soon as practicable after identifying a rupture in accordance with § 192.634; and~~
- ~~(iii) Operators must achieve complete segment shut-off and isolation as soon as practicable after rupture detection but within 40 minutes of rupture identification in accordance with § 192.634.~~
- ~~(2) *Compliance deadlines.* The risk analysis and assessments specified in paragraph (c) of this section must be completed prior to placing into service onshore transmission pipelines constructed or where 2 or more contiguous miles have been replaced after **[DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE]**. Implementation of risk analysis and assessment findings for rupture mitigation valves must meet § 192.634.~~
- (1) *Periodic evaluations.* Risk analyses and assessments conducted under paragraph (c) of this section must be reviewed by the operator for new or existing operational and integrity matters that would affect rupture mitigation on an annual basis, not to exceed a period of 15 months, or within 3 months of an incident or safety-related condition, as those terms are defined at §§ 191.3 and 191.23, respectively, and certified by the signature of a senior executive of the company.

[ . . . ]

#### X. Changes to Alternative MAOP Requirements Should Be Prospective Only

In the NPRM, PHMSA requests comments on whether modifications to the Alternative MAOP requirements in § 192.620 are appropriate as part of the Proposed Rule.<sup>45</sup> Because the scope of the Proposed Rule covers new and entirely replaced pipelines, any changes to alternative MAOP requirements should be prospective only. PHMSA has not presented any evidence suggesting that the existing one-hour response requirement in § 192.620(d) is insufficient to ensure safety following a gas pipeline rupture. Retroactively adding new valves or automating existing valves to achieve a 40-minute performance standard is less practicable and more resource-intensive than installing valves or automation at the time of construction.

The Associations support applying the requirements of §§ 192.179(e) and §§ 192.634 prospectively to new and replaced pipelines that are operated under § 192.620. PHMSA does not need to make any changes to §§ 192.620 to effectuate this. Sections 192.179(e) and §§ 192.634, as drafted, will apply to new and replaced pipelines that are operated under § 192.620. Retaining the one-hour response standard in § 192.620(d) is necessary to address existing pipelines operating under § 192.620 today.

#### XI. The Performance Requirements in Proposed § 192.634 Are Not Appropriate or Practical for Existing Pipelines

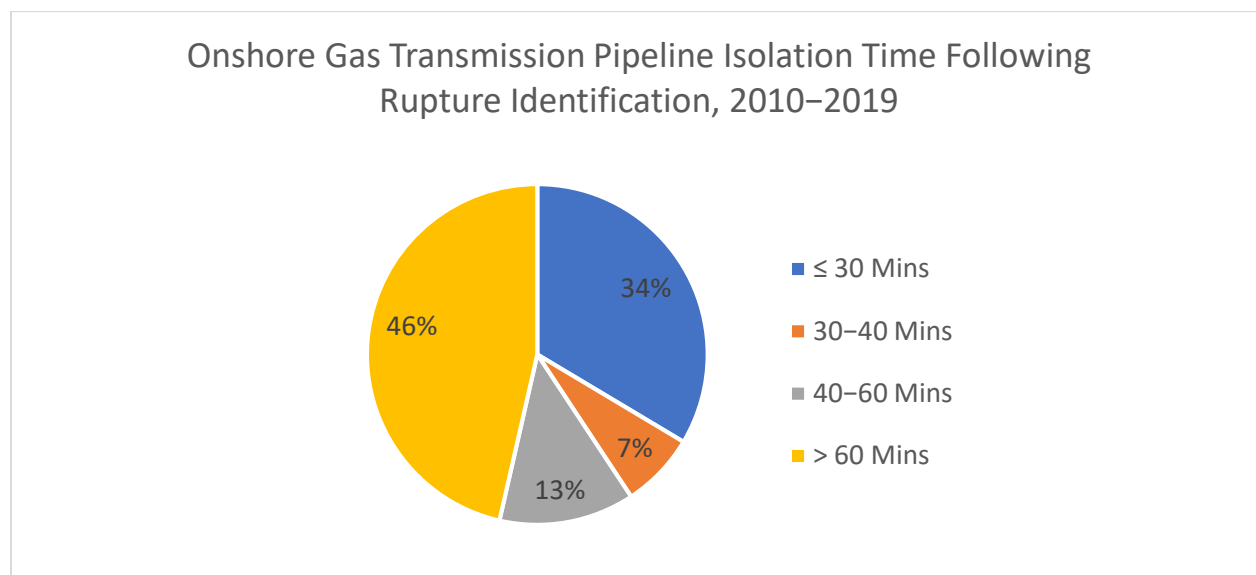
The 40-minute response time proposed in § 192.634 is on the leading edge of what is practicable under currently-available technologies that could be applied to new and replaced pipelines. Therefore, the Associations wish to note that it would not be practicable or appropriate to apply the performance standards in § 192.634 to existing pipelines, should PHMSA consider such a proposal in a future rulemaking.

---

<sup>45</sup> Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards, 85 Fed. Reg. at 7,173.

Since the early 2010s, many gas transmission operators have focused on achieving 60-minute response times in populated areas. INGAA members committed to doing so in 2011.<sup>46</sup> Multiple PHMSA special permits contain a 60-minute response time requirement.<sup>47</sup> Operators have proactively taken steps to attain the 60-minute response target while the current rulemaking has been pending for almost a decade. Operators should not be penalized for taking steps to enhance safety during the pendency of this rulemaking by now having to retroactively attain a 40-minute response time on existing pipelines.

Even for new and replaced pipelines, attaining the 40-minute response time will push the limit of what is currently technologically and operationally possible. Figure 1 below tabulates the response time following PHMSA-reportable onshore gas transmission pipeline ruptures from 2010–2019.<sup>48</sup> For almost 60% of ruptures, response time was greater than 40 minutes. The data below and the operational and technological experience of the Associations’ member suggest that a 40-minute response time would be impracticable for many existing pipelines today, as would any response time shorter than 40 minutes for new and replaced pipelines.



**Figure 1: Time to shutdown following rupture identification for PHMSA-reported onshore gas transmission incidents involving a rupture, 2010-2019.**

<sup>46</sup> Comments of INGAA on Advanced Notice of Proposed Rulemaking: Safety of Gas Transmission, No. PHMSA-2011-0023 (Nov. 2, 2011), <https://www.regulations.gov/document?D=PHMSA-2011-0023-0006>.

<sup>47</sup> See, e.g., PHMSA, Grant of Waive to Kinder Morgan Louisiana Pipeline, LLC, No. PHMSA-2006-25803 (Apr. 19, 2007), [https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/KMLP\\_04-13-2007\\_508compliant.pdf](https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/KMLP_04-13-2007_508compliant.pdf); PHMSA, Grant of Special Permit to CenterPoint Energy Gas Transmission Company, No. PHMSA-2006-25802 (Sep. 5, 2006), [https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/CenterPoint\\_2007-07-31%20now508compliant.pdf](https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/CenterPoint_2007-07-31%20now508compliant.pdf).

<sup>48</sup> See PHMSA, Pipeline Incident Flagged Files (Mar. 10, 2020), <https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files>.

## XII. Consolidated Recommendations for Changes to Regulatory Text of Proposed Rule

Below is a consolidated set of Associations' proposed modifications to the Proposed Rule regulatory text **in red**. These proposed modifications were explained and included in Parts I—XI above.

### §192.3 Definitions.

**Notification of Potential Rupture** means any of the following events that involve an **unintentional and uncontrolled release of a large volume of gas from a transmission pipeline**:

- (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 **meeting defined in paragraphs (2) or (3) of this definition is observed by or reported to the operator**;
- (2) **The operator observes** an unanticipated or unplanned pressure loss **outside of the pipeline's normal operating parameters, as defined in the operator's procedures, 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) **The operator observes** an unexplained flow rate change, pressure change, instrumentation indication, or equipment function that may be representative of an event **meeting defined in paragraph (2) of this definition**.

Note: ~~Rupture identification~~ **Notification** occurs when a rupture, as defined in this section, is first observed by or reported to pipeline operating personnel or a controller.

[ . . . ]

### § 192.179 Transmission line valves.

[ . . . ]

- (e) **For** all onshore transmission line segments with diameters greater than or equal to 6 inches that are **newly** constructed or **where 2 or more contiguous miles have been entirely replaced after [DATE 24 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE], the operator** must **install** ~~have~~ automatic shutoff valves, remote-control valves, or equivalent technology **whenever an additional valve must be installed at intervals to meeting** the appropriate valve spacing requirements of this section. An operator may only install a manual valve under this paragraph if it can demonstrate to PHMSA that installing an automatic shutoff valve, remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. An operator using alternative equivalent technology or **a** manual valve must notify PHMSA in accordance with the procedure in **paragraph (f), § 192.634(h)**. ~~All valves and technology installed under this paragraph must meet the requirements of § 192.634(c), (d), (f), and (g). This subsection does not apply to segments that have an MAOP less than 30 percent of the specified minimum yield strength or a potential impact radius (PIR) less than or equal to 150 feet.~~
- (f) **Alternative equivalent technology or manual valves. If an operator elects to use alternative equivalent technology or a manual valve in accordance with paragraph (e), the operator must notify PHMSA at least 90 days in advance of installation or use in accordance with § 192.18. The operator must include a technical and safety evaluation in its notice to PHMSA, including design, construction, and operating procedures for the alternative equivalent technology or manual valve. Operators installing manual valves must also demonstrate that installing an automatic shutoff valve, a remote-control valve, or equivalent technology would be economically, technically, or**

operationally infeasible. An operator may proceed to use the alternative equivalent technology or manual valve 91 days after submitting the notification unless it receives a letter from the Associate Administrator of Pipeline Safety informing the operator that PHMSA objects to the proposed use of the alternative equivalent technology or manual valve or that PHMSA requires additional time to conduct its review.

- (g) Replacements. Nothing in this section applies to replacements of existing pipeline segments involving less than two miles of contiguous pipe, except as required under § 192.610. The valve spacing requirements of this section do not apply to pipeline replacements that comply with the rupture-mitigation valve spacing requirements in § 192.634(b).

[...]

#### **§ 192.610 Change in class location: change in valve spacing.**

- (a) If a class location change on a transmission line occurs after [EFFECTIVE DATE OF FINAL RULE] and results in pipe replacement of two or more contiguous miles to meet the maximum allowable operating pressure requirements in §§ 192.611, 192.619, or 192.620, then the requirements in §§ 192.179 and 192.634, as appropriate, apply to the new class location, and the operator must install valves as necessary to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with § 192.611(d).
- (b) If a class location change on a transmission line occurs after [EFFECTIVE DATE OF FINAL RULE] and results in pipe replacement of less than two contiguous miles to meet the maximum allowable operating pressure 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 segment; or
  - (2) Install or use existing rupture-mitigation valves so that the entirety of the replaced segment is between at least two rupture-mitigation valves. The distance between rupture-mitigation valves for the replaced segment must not exceed 20 miles. The rupture-mitigation valves must comply with all requirements of § 192.634(c)-(f).
- (c) This section does not apply to pipe replacements that are less than 2,000 contiguous feet.

[...]

#### **§192.615 Emergency plans.**

- (a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
- (1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.
  - (2) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (9-1-1 emergency call center), as well as fire, police, and other public officials, to learn the responsibility, resources, jurisdictional area, and emergency contact telephone numbers for both local and out-of-area calls of each government organization that may respond to a pipeline emergency, and to inform the officials about the operator's ability to respond to the pipeline emergency and means of communication. 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.
  - (3) Prompt and effective response to a notice of each type of emergency, including the following:
    - (i) Gas detected inside or near a building.

- (ii) Fire located near or directly involving a pipeline facility.
- (iii) Explosion occurring near or directly involving a pipeline facility.
- (iv) Natural disaster.
- (4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.
- (5) Actions directed toward protecting people first and then property.
- (6) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, and pressure reduction, in any section of the operator's pipeline system necessary to minimize hazards of released gas to life, property or the environment. Each operator installing valves in accordance with § 192.179(e) or subject to the requirements in § 192.634 must also evaluate and identify a **notification of potential** rupture as defined in § 192.3 as being an actual rupture event or non-rupture event in accordance with operating procedures as soon as practicable ~~following but within 10 minutes of~~ the initial notification to or by the operator, regardless of how the rupture is initially detected or observed.
- (7) Making safe any actual or potential hazard to life or property.
- (8) ~~Notifying the appropriate public safety answering point (9-1-1 emergency call center), as well as fire, police, and other public officials of gas pipeline emergencies to coordinate and share information to determine the location of the release, including both planned responses and actual responses during an emergency. The operator (pipeline controller or the appropriate operator emergency response coordinator) must~~ Immediately and directly notifying the appropriate public safety answering point (9-1-1 emergency call center) or other coordinating agency for the communities and jurisdictions in which the pipeline is located after the operator determines a rupture has occurred when a release is indicated and rupture-mitigation valve closure is implemented **to coordinate and share information to determine the location of the release.**
- (9) Safely restoring any service outage.
- (10) Beginning action under §192.617, if applicable, as soon after the end of the emergency as possible.
- (11) Actions required to be taken by a controller during an emergency in accordance with the operator's emergency plans and §192.631 and 192.634.
- (b) Each operator shall:
  - (1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.
  - (2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.
  - (3) Review employee activities to determine whether the procedures were effectively followed in each emergency.
- (c) Each operator shall establish and maintain liaison with the appropriate public safety answering point (9-1-1 emergency call center), as well as fire, police, and other public officials to:
  - (1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;
  - (2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;
  - (3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and
  - (4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

[ . . . ]

**§192.617 Investigation of ~~incidents-failures~~.**

- (a) *Post-incident procedures.* Each operator must establish and follow post-incident 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, to determine the causes and contributing factors of the ~~failure-or~~ incident and minimize the possibility of a recurrence.
- (b) *Post-incident lessons learned.* Each operator must develop, implement, and incorporate, **if appropriate and practicable**, lessons learned from a post-incident review into its procedures, including in pertinent operator personnel training and qualification programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.
- (c) *Analysis of rupture and valve shut-offs; preventive and mitigative measures.* If an ~~failure-or~~ incident involves a rupture **of a gas transmission line as defined in § 192.3** or the closure of a rupture-mitigation valve as defined in § 192.634, the operator must also conduct a post-incident analysis of all factors impacting the release volume and the consequences of the release, and identify and implement, **if appropriate and practicable**, preventive and mitigative measures to reduce or limit the release volume and damage in 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:
  - (1) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the release ~~or failure event~~;
  - (2) Appropriateness and effectiveness of procedures and pipeline systems, including SCADA, communications, valve shut-off, and operator personnel;
  - (3) Actual response time from rupture detection to initiation of mitigative actions, and the appropriateness and effectiveness of the mitigative actions taken;
  - (4) Location and the timeliness of actuation of rupture-mitigation valves identified under § 192.634; and
  - (5) All other factors the operator deems appropriate.
- ~~(d) *Rupture post-incident summary.* If a failure or incident involves a rupture as defined in § 192.3 or the closure of a rupture-mitigation valve as defined in § 192.634, the operator must complete a summary of the post-incident review required by paragraph (c) of this section within 90 days of the failure or incident, and while the investigation is pending, conduct quarterly status reviews until completed. The post-incident summary and all other reviews and analyses produced under the requirements of this section must be reviewed, dated, and signed by the appropriate senior executive officer. The post-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.~~

[ . . . ]

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

- (a) *Applicability.* For onshore transmission pipeline segments with nominal diameters of 6 inches or greater in high consequence areas or Class 3 or Class 4 locations that are **newly** constructed or where 2 or more contiguous miles have been replaced after **[DATE 24 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE]**, an operator must install **or use existing** rupture-mitigation valves according to the requirements of this section. Rupture-mitigation valves must be operational within **14 7** days of placing the new or replaced pipeline segment in service, **unless the operator notifies PHMSA in accordance with § 192.18 that a rupture-mitigation valve cannot be made operational**



within 14 days. This section does not apply to segments that have an MAOP less than 30 percent of the specified minimum yield strength or to segments outside of high consequence areas that have a potential impact radius (PIR) less than or equal to 150 feet.

(b) *Maximum spacing between valves.* Rupture-mitigation valves must be installed in accordance with the following requirements:

- (1) **Shut-off Segment.** For purposes of this subsection, “shut-off segment” means the segment of pipe located between the upstream mainline valve closest to the upstream endpoint of the new or replaced Class 3 or 4 or high consequence area segment and the downstream mainline valve closest to the downstream endpoint of the new or replaced Class 3 or 4 or high consequence area segment. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline 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 gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or 4 locations or high consequence area segments may be contained within a single shut-off segment.
- (2) **Rupture-Mitigation Valves.** Valves needed to isolate the entire shut-off segment in accordance with the spacing requirements of this subsection are “rupture-mitigation valves.” The operator is not required to select the closest valve to the shutoff segment as the rupture-mitigation valve. The operator may use a station valve as a rupture-mitigation valve. A downstream rupture-mitigation valve is not required where the distance between the end of the transmission line and the upstream rupture-mitigation valve complies with the spacing requirements in this subsection.
- (3) **High Consequence Areas.** For purposes of this paragraph (b)(1), “shut-off segment” means the segment of pipe located between the upstream mainline valve closest to the upstream high consequence area segment endpoint and the downstream mainline valve closest to the downstream high consequence area segment endpoint so that the entirety of the high consequence area segment is between at least two rupture-mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, then the segment also extends to the nearest 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). All such valves on a shut-off segment are “rupture-mitigation valves.” Multiple high consequence areas may be contained within a single shut-off segment. The distance between rupture-mitigation valves for each shut-off segment **containing a high consequence area** must not exceed:
  - (i) 8 miles if one or more high consequence areas in the shutoff segment is in a Class 4 location;
  - (ii) 15 miles if one or more high consequence areas in the shutoff segment is in a Class 3 location, and
  - (iii) 20 miles if all high consequence areas in the shutoff segment are located in Class 1 or 2 locations, or
  - (iv) The mainline valve spacing requirements of § 192.179 when mainline valve spacing does not meet § 192.634(b)(31)(i), (ii), or (iii).
- (4) **Class 3 locations.** For purposes of this paragraph, “shut-off segment” means the segment of pipe located between the upstream mainline valve closest to the upstream endpoint of the Class 3 location and the downstream mainline valve closest to the downstream endpoint of the Class 3 location so that the entirety of the Class 3 location is between at least two rupture-mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves,

~~the shut-off segment also extends to the nearest 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). All such valves on a shut-off segment are “rupture mitigation valves.” Multiple Class 3 locations may be contained within a single shut-off segment. The distance between mainline valves serving as rupture-mitigation valves for each shut-off segment containing a class 3 location must not exceed 15 miles.~~

(5) *Class 4 locations.* ~~For purposes of this paragraph, “shut-off segment” means the segment of pipe between the upstream mainline valve closest to the upstream endpoint of the Class 4 location and the downstream mainline valve closest to the downstream endpoint of the Class 4 location so that the entirety of the Class 4 location is between at least two rupture mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, the shut-off segment also extends to the nearest 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). All such valves on a shut-off segment are “rupture mitigation valves.” Multiple Class 4 locations may be contained within a single shut-off segment. The distance between mainline valves serving as rupture-mitigation valves for each shut-off segment containing a class 4 location must not exceed 8 miles.~~

(6) *Laterals.* Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have rupture-mitigation valves that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of these 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 constructed or where 2 or more contiguous miles have been replaced after [DATE 24 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE], a check valve may be used as a rupture-mitigation valve where it is positioned to stop flow into the lateral. Check valves used as rupture-mitigation valves in accordance with this paragraph are not subject to subsections (c)-(f).

(7) *Crossovers.* An operator may use a manual valve as a rupture mitigation valve for a crossover connection if during normal operations the valve is closed to prevent the flow of gas 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 locked in accordance with the operator’s lock-out and tag-out procedures.

~~(c) Valve shut-off time for rupture mitigation. Upon identifying a rupture, the operator must, as soon as practicable:~~

~~(1) Commence shut-off of the rupture mitigation valve or valves which would have the greatest effect on minimizing the release volume and other potential safety and environmental consequences of the discharge to achieve full rupture mitigation valve shut-off within 40 minutes of rupture identification; and~~

~~(2) Initiate other mitigative actions appropriate for the situation to minimize the release volume and potential adverse consequences.~~

(c) *Valve shut-off capability.* Onshore transmission line rupture-mitigation valves must have actuation capability (i.e., remote-control shut-off, automatic shut-off, equivalent technology, or manual shut-off where personnel are in proximity) to ensure pipeline ruptures are promptly mitigated based upon maximum valve shut-off times, location, and spacing specified in paragraphs (b) and (d) of this section to mitigate the volume and consequence of gas released.

(d) *Valve shut-off methods.* All onshore transmission line rupture-mitigation valves must be actuated by



one of the following methods to mitigate a rupture as soon as practicable but within 40 minutes of rupture identification:

- (1) Remote control from a location that is continuously staffed with personnel trained in rupture response to provide immediate shut-off following identification of a rupture or other decision to close the valve;
  - (2) Automatic shut-off following identification of a rupture; or
  - (3) Alternative equivalent technology that is capable of mitigating a rupture in accordance with this section.
  - (4) *Manual operation upon identification of a rupture.* Operators using a manual valve in accordance with § 192.179(e), must appropriately station personnel to ensure valve shut-off in accordance with ~~paragraph (c) of~~ this section. 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 40-minute total response time in ~~paragraph (c)(1) of~~ this section.
  - (5) **Open Valves. An operator may leave a rupture-mitigation valve open for more than 40 minutes following rupture identification if the operator, in coordination with appropriate local responders and public authorities, determines that is safe to leave the valve open.**
- (e) *Valve monitoring and operation capabilities.* Onshore transmission line rupture- mitigation valves actuated by methods in paragraph (d) of this section must be capable of being:
- (1) Monitored or controlled by either remote or onsite personnel;
  - (2) Operated during normal, abnormal, and emergency operating conditions; **and**
  - (3) Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. **For automatic shut-off valves, valve status need not be monitored remotely if the operator has the capability to monitor pressures or gas flow rates on the pipeline to be able to identify and locate a rupture.** Pipeline segments that use manual valve operation must have the capability to monitor pressures ~~and or~~ gas flow rates on the pipeline to be able to identify and locate a rupture;
  - ~~(4) Initiated to close as soon as practicable after identifying a rupture and with complete valve shut-off within 40 minutes of rupture identification as specified in paragraph (c) of this section; and~~
  - ~~(5) Monitored and controlled by remote personnel or must have a back-up power source to maintain SCADA or other remote communications for remote control shut-off valve or automatic shut-off valve operational status.~~
- (f) *Monitoring of valve shut-off response status.* Operating control personnel must continually monitor rupture-mitigation valve position and operational status of all rupture-mitigation valves for the affected shut-off segment during and after a rupture event until the pipeline segment is isolated. Such monitoring must be maintained through continual electronic communications with remote instrumentation or through continual verbal communication with onsite personnel stationed at each rupture-mitigation valve, via telephone, radio, or equivalent means.
- ~~(h) Alternative equivalent technology or manual valves for onshore transmission rupture mitigation. If an operator elects to use alternative equivalent technology or manual valves in accordance with § 192.179(e), the operator must notify PHMSA at least 90 days in advance of installation or use in accordance with § 192.949. The operator must include a technical and safety evaluation in its notice to PHMSA, including design, construction, and operating procedures for the alternative equivalent technology or manual valve. Operators installing manual valves must also demonstrate that installing an automatic shutoff valve, a remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. An operator may proceed to use the~~

~~alternative equivalent technology or manual valves 91 days after submitting the notification unless it receives a letter from the Associate Administrator of Pipeline Safety informing the operator that PHMSA objects to the proposed use of the alternative equivalent technology or manual valves or that PHMSA requires additional time to conduct its review.~~

[ . . . ]

#### § 192.745 Valve maintenance: Transmission lines.

- (a) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.
- (b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.
- ~~(c) For each valve installed under § 192.179(e) and each rupture-mitigation valve under § 192.634 that is a remote control shut-off or automatic shut-off valve, or that is based on alternative equivalent technology, the operator must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with § 192.631(c) and (e).~~
- (c) For ~~each~~ rupture-mitigation valves under § 192.634 that ~~are is~~ manually or locally operated (**i.e., not automatic or remotely controlled**):
  - (1) Operators must establish the 40-minute total response time as required by § 192.634 through an initial drill and through periodic validation as required in paragraph ~~(d)~~(2) of this section. Each phase of the drill response must be reviewed and the results documented to validate the total response time, including valve shut-off, as being less than or equal to 40 minutes following rupture identification.
  - (2) A mainline valve serving as a rupture-mitigation valve within each pipeline system and within each operating or maintenance field work unit must be randomly selected for an annual 40-minute total response time validation drill that simulates **reasonable** worst-case conditions for that location to ensure compliance. **Operators are not required to fully close the rupture-mitigation valve during the drill.** The response drill must occur at least once each calendar year, with intervals not to exceed 15 months.
  - (3) If the 40-minute maximum response time cannot be validated or achieved in the drill, the operator must revise response efforts to achieve compliance with § 192.634 no later than **12 6** 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; and
    - (ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and
    - (iii) Any other areas identified by the operator as needing improvement.
- (d) Each operator must take remedial measures to correct any valve installed under § 192.179(e) or any rupture-mitigation valve identified in § 192.634 that is found 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 6** months after finding that the valve is inoperable or unable to maintain shut-off. **An operator must notify PHMSA in accordance with § 192.18 if a valve cannot be repaired or replaced within 12 months;** and
  - (2) Designate an alternative **shut-off compliant** valve within 7 calendar days of the finding while repairs are being made **and document an interim response plan.**

[...]

**§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 an automatic shut-off valve (ASV) or remote-control valve (RCV) would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of **rupture 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.

~~(1) *Protection of onshore transmission high consequence areas from ruptures.* An operator of an onshore transmission pipeline segment that is constructed, or that has 2 or more contiguous miles replaced, after **[DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE]** and is greater than or equal to 6 inches in nominal diameter and is located in a high consequence area must provide for the additional protection of those pipeline segments to assure the timely termination and mitigation of rupture events by complying with §§ 192.615(a)(6), 192.634, and 192.745. At a minimum, the analysis specified in paragraph (c) of this section must demonstrate that the operator can achieve the following standards for termination of rupture events:~~

- ~~(i) Operators must identify a rupture event as soon as practicable but within 10 minutes of the initial notification to or by the operator, in accordance with § 192.615(a)(6), regardless of how the rupture is initially detected or observed;~~
- ~~(ii) Operators must begin closing shut-off segment rupture mitigation valves as soon as practicable after identifying a rupture in accordance with § 192.634; and~~
- ~~(iii) Operators must achieve complete segment shut-off and isolation as soon as practicable after rupture detection but within 40 minutes of rupture identification in accordance with § 192.634.~~

~~(2) *Compliance deadlines.* The risk analysis and assessments specified in paragraph (c) of this section must be completed prior to placing into service onshore transmission pipelines constructed or where 2 or more contiguous miles have been replaced after **[DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE]**. Implementation of risk analysis and assessment findings for rupture mitigation valves must meet § 192.634.~~

(1) *Periodic evaluations.* Risk analyses and assessments conducted under paragraph (c) of this section must be reviewed by the operator for new or existing operational and integrity matters that would affect rupture mitigation on an annual basis, not to exceed a period of 15 months, or within 3 months of an incident or safety-related condition, as those terms are defined at §§ 191.3 and 191.23, respectively, and certified by the signature of a senior executive of the company.

[...]

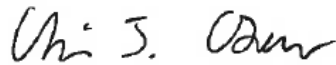
Respectfully submitted,  
Date: April 6, 2020



Erin Kurilla, Vice President, Operations and Pipeline Safety  
American Public Gas Association  
201 Massachusetts Avenue, NE  
Washington, D.C. 20002  
(202) 905-2904  
[ekurilla@apga.org](mailto:ekurilla@apga.org)



Dave Murk, Pipeline Manager  
American Petroleum Institute  
1220 L Street, NW  
Washington, D.C. 20005  
(202) 682-8000  
[murkd@api.org](mailto:murkd@api.org)



C.J. Osman, Vice President, Operations, Safety and Integrity  
Interstate Natural Gas Association of America  
20 F Street, NW  
Washington, D.C. 20001  
(202) 216-5912  
[cj Osman@ingaa.org](mailto:cjosman@ingaa.org)



Sonal Patni, Director, Operations and Engineering Services  
American Gas Association  
400 North Capitol Street, NW  
Washington, D.C. 20001  
(202) 824-7328  
[spatni@aga.org](mailto:spatni@aga.org)



Christina Sames, Vice President, Operations and Engineering  
American Gas Association  
400 North Capitol Street, NW  
Washington, D.C. 20001  
(202) 824-7214  
[csames@aga.org](mailto:csames@aga.org)