Regulatory Impact Analysis

Amendments to Parts 192 and 195 to Require Valve Installation and Minimum Rupture Detection Standards Final Rule

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Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
U. S. Department of Transportation

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ABBREVIATIONS AND TERMS

This section defines key abbreviations in this report.

ABBREVIATIONS

ASV – automatic shut-off valve

bbls – barrels, equal to 42 U.S. gallons (typical volume metric for hazardous liquid pipelines)

CARB – California Air Resources Board

CFR – Code of Federal Regulations

EFRD – emergency flow restricting device

GIS – geographic information system

HCA – high consequence area

HVL – highly volatile liquid

IM – integrity management

LDS – leak detection system

MCF – thousand (standard) cubic feet (typical volume metric for gas pipelines)

MOV – manually operated valve

NTSB – National Transportation Safety Board

ORNL – Oak Ridge National Laboratory

OPID – operator identification number

PHMSA – Pipeline and Hazardous Materials Safety Administration

PIR – potential impact radius

PSR – pipeline safety regulations

P&M – preventive and mitigative measures

RCV – remote-control valve

RMV – rupture-mitigation valve

RTU – remote terminal unit

SCADA – supervisory control and data acquisition system

TERMS

Actuated valve – All valves have some sort of actuator. For this analysis, an actuated valve is a locally operated valve equipped with either an electric, hydraulic, pneumatic, or other powered actuator.

Automatic shut-off valve (ASV) - An ASV will close automatically when either a pressure loss or a flow rate increase exceeds a predetermined point.

Check valve - A check valve permits fluid to flow freely in one direction while preventing flow in the opposite direction. Although a check valve can be either an ASV or an EFRD in some applications, the final rule will only allow the use of a check valve as a rupture-mitigation valve in limited circumstances and if an operator can demonstrate the operational and protective equivalence for product flow shut-off in response to a rupture.

Emergency flow restricting device (EFRD) – The hazardous liquid integrity management (IM) regulations in part 195 define an EFRD as a check or remote-control valve (RCV).

Manual Valve – In this analysis, a manual valve has an unpowered or hand-operated actuator.

Operator identification number (OPID) – A unique identifier assigned to pipeline operators by PHMSA for a pipeline system. An operator may have a single or multiple OPIDs.

Property damage – As defined in PHMSA's accident reporting instructions, property damage includes costs due to: damage to the operator's facilities and to the property of others; facility repair and replacement; environmental cleanup and damage; and the cost of lost commodity (for hazardous liquid pipelines only).

Remote-control valve (RCV) - Any valve that is controlled from a location remote from where the valve is installed. Remote operation or control could be from a control center that monitors and controls pipeline facilities nationwide, regionally, or locally. An RCV is usually operated in response to a signal from the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.

Rupture – The final rule defines conditions for the notification of potential ruptures in § 192.635 for gas pipelines and in § 195.417 for hazardous liquid pipelines as indications that any type of large-volume, rapidly occurring, and uncontrolled release or failure event potentially exists. Ruptures will include events that have rupture-like characteristics in terms of pressure and flow profiles, including, but not limited to, failures due to mechanical punctures, line breaks and other large-scale failures; seam splits; large through-wall cracks; sheared lines due to natural or other outside force damage; and valves inadvertently left open. A rupture could be indicated by any of the following events that signal an uncontrolled release of a large volume of product over a short period of time: (1) an unanticipated or unplanned pressure loss of 10 percent or more, occurring within a time interval of 15 minutes or less (with certain specific exceptions relevant to gas and liquid pipelines); (2) an unexplained flow-rate change, pressure change, instrumentation indication, or equipment function; or (3) an apparent large-volume, uncontrolled release of gas or a failure observed by operator personnel, the public, or public authorities.

Rupture-mitigation valve (RMV) – ASV or RCV that satisfies the requirements of the final rule.

ES. EXECUTIVE SUMMARY

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is finalizing regulations to improve pipeline operator responses to large-volume, uncontrolled pipeline releases that may occur during the operation of certain large-diameter (6 inches or greater) onshore natural gas transmission, Type A natural gas gathering, and hazardous liquid (including carbon dioxide) pipelines.

This document provides analysis of the costs and benefits of the final rule and regulatory alternatives considered by PHMSA.

ES-1. INTRODUCTION

High profile pipeline ruptures in the past decade have raised concern over operator response times. In 2010, there was a rupture and explosion on a natural gas pipeline operated by Pacific Gas and Electric (PG&E) in San Bruno, CA. PG&E took more than 90 minutes[1] to stop the flow of gas to its pipeline. As a result of the PG&E incident, eight people died, 51 people were injured, 38 homes were destroyed, and an additional 70 homes were damaged. The National Transportation Safety Board (NTSB) conducted a post-incident investigation and recommended mandating the use of automatic or remote-control valves on natural gas pipelines in high consequence areas (HCA) and Class 3 and Class 4 locations.

Also, in 2010, Enbridge Energy failed to identify and promptly respond to a hazardous liquid pipeline rupture in Marshall, MI. As a result, the ruptured pipeline leaked for 18 hours and released over 800,000 gallons of crude oil into the Kalamazoo River and the surrounding wetlands. The NTSB accident report for the Enbridge accident documents that the operator paid over $600 million in environmental remediation alone.[2] Costs to the company later increased to $1.21 billion, which does not include undetermined third-party remediation costs and environmental damages.[3]

ES-2. NEED FOR THE REGULATION

Although some individual operators have installed ASVs and RCVs in response to high-profile incidents, and existing regulations require operators to evaluate risks and take preventative and mitigating (P&M) measures accordingly, the potential for unmitigated consequences of major ruptures still remains high without an enforceable standard. Sections 195.452 and 192.935 of the Pipeline Safety Regulations (PSR) require operators to implement P&M at locations that "could

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[1] "However, PG&E took 95 minutes to stop the flow of gas and to isolate the rupture site – a response time that was excessively long and contributed to the extent and severity of property damage and increased the life-threatening risks to the residents and emergency responders." NTSB, Accident Report PAR-11/01, "Pacific Gas and Electric Company; Natural Gas Transmission Pipeline Rupture and Fire; San Bruno, CA; September 9, 2010" (Aug. 30, 2011), https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf.

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

[3] Garret Ellison, "New price tag for Kalamazoo River oil spill cleanup: Enbridge says $1.21 billion". Grand Rapids Press, November 5, 2014, updated April 3, 2019. https://www.mlive.com/news/grand-rapids/2014/11/2010_oil_spill_cost_enbridge_1.html

affect high consequence areas." One of the P&M measures is for an operator to determine the need for emergency flow restricting devices (EFRD) to protect HCAs from pipeline releases. Some of the factors used to determine the need for these types of valves are the swiftness of leak detection, shutdown capabilities, terrain, and product type. The PG&E incident and the Enbridge accident had slow response times (95 minutes and 18 hours, respectively).

The final rule requires operators installing rupture-mitigation valves (RMVs) [4] or alternative equivalent technologies pursuant to the final rule to identify ruptures and close valves to isolate the ruptured segment as soon as practicable, not to exceed 30 minutes from rupture identification.

An RMV might be infeasible if communications and security cannot be reliably established at the valve site. RMVs also might not be feasible in areas where the right-of-way is not available for installing equipment or a power source is not available because of space limitations. Alternative equivalent technologies may be needed to meet the standard in site-specific circumstances not amenable to employing ASVs and RCVs (such as remote areas where communications capabilities are limited). Also, for natural gas pipelines in some circumstances, PHMSA will allow the expansion of valve spacing by one class location (further distance apart) to resolve this issue. For example, if a Class 3 location cannot accommodate a valve at the location required by the Class 3 spacing requirement, then an exception can be allowed that increases the spacing requirement to the Class 2 requirement and to a location in which an ASV or RCV can be accommodated.

These requirements apply to newly-constructed and entirely replaced,[5] large-diameter (6 inches or greater) onshore gas transmission, Type A natural gas gathering, and onshore hazardous liquid pipelines. For gas pipelines, Class 1 or Class 2 locations that have a potential impact radius (PIR) less than or equal to 150 feet are excluded.

ES-3. BASELINE FOR THE ANALYSIS

Table ES-1 reports the number of operator identifications for onshore gas and hazardous liquid transmission and gathering pipelines. On average, operators have installed 5,556 miles of onshore transmission and gathering pipelines annually from 2015-2019.[6]

Table ES-1. Number of Potentially Affected Entities*

System Type	Operators of Onshore Pipelines[7]
Gas pipeline	1,304
Hazardous liquid pipeline	508

[4] The final rule defines an RMV as "an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture."
[5] The final rule defines an "entirely replaced" pipeline as a pipeline that has 2 or more contiguous miles are being replaced with new pipe within a stretch of 5 contiguous miles within a 24-month period.
[6] Based on PHMSA Annual Report data at https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.
[7] Id.

Table ES-1. Number of Potentially Affected Entities[*]	
System Type	**Operators of Onshore Pipelines[7]**
Source: PHMSA Annual Report data, available at https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids. [*] Represents number of operator identifications (OPID). An OPID may be associated with both gas and hazardous liquid pipelines.	

The PSR currently require operators to identify pipeline threats, conduct risk assessments, and take additional measures as necessary to mitigate the consequences of possible failures of pipelines which are in or could affect HCAs. These additional measures include the installation of ASVs, RCVs, or EFRDs on existing pipelines if determined necessary. Also, under part 194 of the existing PSR, operators of onshore hazardous liquid pipelines must prepare response plans to reduce the environmental impact of oil discharges, including a drill program for emergency response exercise. However, in parts 192 and 195, operators are not currently required to identify a rupture and isolate a ruptured pipeline segment within any specified timeframe; specific guidance for where, when and how ASVs or RCVs (or, in the case of hazardous liquid pipelines, EFRDs) are to be used is limited to integrity management (IM) regulated pipelines.[8]

Final Environmental Impact Statements (FEISes) for pipeline projects proposed after the passage of the Pipeline Safety Act of 2011 show that, at least for major interstate pipeline projects requiring Federal Energy Regulatory Commission (FERC) review and approval, operators have been committing to a substantial degree of remote monitoring and operation of valves. For this analysis, PHMSA's baseline scenario accounts for the extent of operators' voluntary use of either locally operated motorized valves or RCVs in the absence of the final rule.

From PHMSA incident report data, between 2010 and 2020, gas transmission and gathering pipeline operators reported 298 ruptures or mechanical punctures to PHMSA, which resulted in 16 fatalities, 88 injuries, and property and environmental costs of $895 million. Hazardous liquid pipeline operators reported 244 ruptures or mechanical punctures over the same period that resulted in 10 fatalities, 13 injuries, and $1.4 billion in property and environmental costs. No comprehensive studies are available comparing the consequences of incidents involving pipelines with and without automated valves.

ES-4. ANALYSIS OF COSTS

The costs of the final rule include incremental program costs to identify ruptures and make other procedural changes. The cost of constructing new pipelines or entirely replacing existing pipelines) may also be incrementally increased to the extent that the baseline valve installation does not meet the regulatory standard (operators are not able to close all valves within 30 minutes after rupture identification). Incremental upgrades to baseline pipeline designs that enable compliance with the standard could include: (1) communications equipment and power supplies needed to monitor pressure and automate actuated valves, or (2) the purchase and

[8] IM regulated gas transmission and hazardous liquid pipelines are pipelines that could, in the event of a leak or failure, affect HCAs. HCAs include: population areas; areas containing drinking water and ecological resources that are unusually sensitive to environmental damage; and commercially navigable waterways.

installation of an actuator for non-actuated valves, in addition to the required remote communications equipment.

PHMSA estimated the number of valves that need to be automated based on annual report data on pipeline installations and baseline data characterizing the types of valves used for new pipeline construction in the absence of the final rule. PHMSA assumed operators installing ASVs/RCVs will be able to meet the standard, and that operators installing locally operated actuated or non-actuated valves will need to modify these valves for remote operation. The final rule will not affect the number of new valves required to accommodate future pipeline construction and replacement; rather, it will affect the type of valve employed, to the extent that the valve would be non-compliant in the baseline.

Automating a locally operated valve involves installing a remote terminal unit, communications equipment, and backup batteries. If the valve lacks an actuator, then the valve also requires the installation of an actuator. PHMSA estimated costs for these components based on operator price information. PHMSA also estimated incremental costs to update existing operator programs consistent with the final revisions to emergency response and incident analysis requirements. PHMSA based this estimate on the number of operators, best professional judgement regarding the level of effort that may be required, and relevant labor rates. The rule may also result in some costs to pipelines and their customers if ASVs are triggered accidentally. PHMSA has not quantified these costs.

Table ES-2 summarizes the total compliance costs including equipment and programmatic costs.

Table ES-2. Summary of Annualized Costs for Final Rule[*] (Millions 2020$)

System Type	Equipment Upgrades	Program Changes	Total
Gas pipeline	$1.9	$0.8	**$2.7**
Hazardous liquid pipeline	$3.0	$0.4	**$3.4**
Total	$5.0	$1.1	**$6.1**

[*] Reflects 7 percent discount rate.
Note: Detail may not add to total due to rounding.

ES-5. ANALYSIS OF BENEFITS

The use of RCVs, ASVs, and alternative equivalent technologies on new and replaced pipelines will allow operators to shut down pipelines quickly in the event of a rupture, mitigating the consequences relative to a pipeline with locally actuated valves that cannot achieve the closure standards of the final rule. For gas pipelines, the most significant benefit of quick pipeline shutdown is improved safety through the reduced fire risk. PHMSA estimates 30 percent of gas pipeline ruptures are ignited; however, time to ignition is not collected in required PHMSA incident reports. Sparking of rupturing material or fill moved by gas pressure can be the source of immediate ignition, or the vapor cloud might not ignite until it expands to an ignition source farther away/later in time. Cutting off the gas by closing a RMV or alternative equivalent technology reduces the chance of igniting a fire and explosion; furthermore, it speeds up the firefighting and rescue operations if the gas does ignite. Together, these factors reduce the likelihood and consequences of post-incident fires. Rapid response to hazardous liquid pipeline ruptures mitigates damages by reducing the volume of product released into the environment, potentially averting catastrophic consequences such as those from the Enbridge incident.

PHMSA is unable to quantify the benefits of incrementally more rapid response times but does note that there are differences in the effects between hazardous liquid and natural gas incidents that are likely to affect the benefits of this final rule for those respective pipelines. The damages of most hazardous liquid pipeline incidents are dominated by cleanup costs.[9] The benefit of a more rapid response time could primarily be measured by the amount of hazardous liquid to clean up. Therefore, it could be possible to estimate the benefit of this rule for hazardous liquid pipelines in terms of the reduction of spill volume after a hazardous liquid pipeline incident. For example, the Enbridge incident resulted in the release of over 800,000 gallons of crude oil when the valves were not closed for 18 hours. The cost of this accident was approximately $1 billion, largely for cleanup of the product spilled into the Kalamazoo River and the surrounding wetlands. With earlier detection, pump shutdown, and valve closure, the product would have been pumped out of the ruptured pipe for, perhaps, 30 minutes instead of 18 hours. Some product would be released from the isolated section after pump shutdown and valve closure, but the size of the spill and the cost of the cleanup would be substantially lower with timely isolation.

In contrast, the potential monetized impacts of natural gas pipeline incidents are not necessarily linearly related to the quantity of natural gas released. Although all releases of natural gas (which is predominantly methane, a potent greenhouse gas) contribute to anthropogenic climate change, those risks depend not only on the volume of methane released, but also whether and how much of that released methane subsequently ignites to release carbon dioxide (a greenhouse gas which has a lower radiative efficiency than methane, but which persists longer in atmosphere). Incidents with smaller property and bodily injury damage costs are more likely to occur in remote locations, and there is often not an ignition source. For incidents with larger damage costs, which often include an ignition, there can be extensive property damages and injuries or fatalities because they occur at locations that are in close proximity to buildings, homes, or other structures. A reduction in the cumulative gas released over these diverse incidents does not imply avoided damages in the way that reducing spill volume does for hazardous liquid pipeline releases. For example, during the PG&E incident, it took the operator 95 minutes to isolate the rupture segment, which resulted in 8 deaths, 51 injuries, the destruction of 38 homes, and damage to 70 homes. The homes destroyed by the initial rupture would not have been saved by earlier valve closure, but the spread of fire beyond those initial loses could have been avoided with earlier valve closure and a more quickly extinguished gas flame.

While the final rule will remove some flexibility from operators, the requirements will apply to Class 3 and Class 4 sites and sites with a greater than 150-foot PIR for gas transmission and to hazardous liquid pipelines where the net benefits are likely to be the most substantial. However, the final rule includes flexibility in equipment and methods used to meet the requirements, so site-specific differences can be accommodated.

[9] Notable exceptions would be incidents involving highly volatile liquid (HVL) pipelines. An incident involving an HVL pipeline can result in ignition and damages similar to a natural gas pipeline.

While the benefits of reducing hazardous liquid spill volume are directly proportional to the time to valve closure as documented in the ORNL 2012 study, the benefits calculation for more rapid gas pipeline valve closure is more complicated. Much greater benefits will be gained when closure times are closer-in-time to the initiation of the rupture. PHMSA believes that when ASV and RCV equipment is installed, the valves can typically be closed much more quickly than the 30-minute limit an operator has determined a rupture is in progress. RMVs and alternative equivalent technologies installed pursuant to the final rule must be closed as quickly as practicable. The value of the commodity lost and emission damages may be reduced thereafter, but property damage will be dependent upon the damage caused by any spreading effects of the gas flame from a continuing feed of natural gas to the fire area. The spreading of a natural gas fire would be dependent upon the proximity of buildings, homes, or other structures near the pipeline, climate conditions and time duration of the natural gas release. As notes above, the PG&E incident took 95 minutes to isolate the rupture segment and resulted in 8 deaths, 51 injuries, the destruction of 38 homes, and damage to 70 homes, which is an example of the potential spreading effect of a gas pipeline rupture.

ES-6. ALTERNATIVES

In addition to the final rule, PHMSA considered two regulatory alternatives for rupture detection and mitigation, including:

- Exclusion of applicability to new pipeline in non-HCA Class 1 and Class 2 locations, in addition the final rule's requirements.
- Applicability to Type A and B gas gathering, versus only to Type A gas gathering pipelines.

The first alternative reduced equipment costs by restricting the milage that the rule is applied to, lowering total costs by 23 percent. The final rule already excludes pipeline with a PIR of less than 150 feet, so this alternative would further exclude larger diameter and higher-pressure pipelines in Class 1 and Class 2 locations covered by the final rule. The alternative was rejected because the minor cost savings were judged unlikely to warrant the increased unquantified risks to public safety and the environment of not regulating the higher PIR pipelines (i.e., those pipelines on which an incident would be more likely to result in personal injury or death). The second alternative was found to add little to the rule costs because little additional pipeline would be regulated, but the benefits are also small because of the comparatively low risk to public safety and the environment from the low-pressure pipelines that are defined as Type B gas gathering pipeline.

1. INTRODUCTION

PHMSA is revising the PSR to improve pipeline operator responses to large-volume, uncontrolled pipeline releases that may occur during the operation of onshore, large diameter (6 inches or greater), natural gas transmission, Type A natural gas gathering, and hazardous liquid (including carbon dioxide) pipelines. The final rule establishes standards for response to pipeline ruptures. This document analyzes the costs and benefits of the final rule and regulatory alternatives.

1.1. BACKGROUND

In 2020, petroleum and natural gas represented approximately 69 percent of U.S. primary energy consumption.[10] PHMSA's annual report data indicate there are approximately 310,463 miles of onshore gas transmission and regulated gathering pipelines, and 224,928 miles of onshore hazardous liquid pipelines in the country operated under the jurisdiction of 49 CFR parts 192 and 195. Because of the risks of transporting natural gas and hazardous liquids, safe operation of these pipelines is critical to protect workers, the public, property, and the environment. Despite improvements to pipeline safety over the years, ruptures still occur and can have significant and severe consequences, both in proximity of the pipelines and, in the case of hazardous liquid pipelines, sometimes many miles away from the pipelines.

PHMSA sets Federal regulations for minimum safety standards that apply to both interstate and intrastate pipelines. State agencies can partner with PHMSA and become certified to oversee those Federal regulations on its behalf. States may also supplement Federal regulations with their own compatible requirements for intrastate pipelines within their States. Other Federal agencies are involved in pipeline regulation but with different authorities and oversight responsibilities. FERC oversees the siting and permitting of interstate pipelines. The Environmental Protection Agency is responsible for regulations related to protection and damages to the environment and its inhabitants. PHMSA, however, remains responsible for regulating the operational safety of pipeline transportation of natural gas, other gases, and hazardous liquids.

PHMSA has previously considered regulations for ASVs and RCVs because of pipeline incidents, Congressional mandates, and NTSB recommendations. Following an incident in Houston, Texas, in 1969, the NTSB recommended a study on developing standards for the rapid shutdown of failed gas pipelines (NTSB, 1970).[11] During a gas transmission pipeline explosion in Edison, NJ, in 1994, the operator took 2.5 hours to close a manual shut-off valve while 8 apartment buildings burned down and 1,500 people were evacuated. In its final report on the Edison incident, the NTSB called for requirements for ASVs or RCVs on high-pressure lines in high-consequence and environmentally sensitive areas (NTSB, 1995).[12]

[10] Energy Information Administration (2020).

[11] NTSB, NTSB-PSS-71-1, "Special Study of Effects of Delay in Shutting Down Failed Pipeline Systems and Methods of Providing Rapid Shutdown" (1970), https://app.ntsb.gov/doclib/reports/1971/PSS711.pdf.

[12] NTSB, PAR-95-1, "Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey" (1995), https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR9501.pdf

In the Accountable Pipeline Safety and Partnership Act of 1996 (Pub. L. 104-304), Congress required PHMSA to study whether installing RCVs is technically and economically feasible, and whether their use would reduce the consequences of ruptures (applied only to interstate gas transmission pipelines). PHMSA studied the issue and conducted workshops leading to the promulgation of the gas transmission pipeline IM final rule (49 CFR part 192, subpart O) in 2003, requiring gas transmission pipeline operators conduct risk assessments to determine whether and where to install ASVs and RCVs.[13] PHMSA promulgated a similar rule for hazardous liquid pipelines (49 CFR 195.452) in 2000.[14]

However, two events in 2010—the PG&E incident and Enbridge accident—highlighted the concerns over slow operator responses to ruptures and the need to mitigate the safety and environmental impacts of pipeline ruptures. The NTSB incident report on the PG&E rupture recommended that PHMSA require the installation of ASVs or RCVs on gas pipelines located in Class 3 and Class 4 locations and HCAs. In section 4 of the Pipeline Safety Act of 2011, Congress mandated the Secretary of Transportation to require, “the use of automatic or remote-controlled shut-off valves, or equivalent technology, where economically, technically, and operationally feasible” on new or fully replaced transmission pipeline facilities.[15]

PHMSA published two advance notices of proposed rulemakings (ANPRM) covering various topics related to hazardous liquid pipeline safety and gas transmission pipeline safety.[16] PHMSA received and evaluated public comments in response to these ANPRMs.

PHMSA further considered three studies on the use and potential regulation for ASVs and RCVs, leak detection systems (LDS), and pipeline operator response capabilities:

- Better Data and Guidance Needed to Improve Pipeline Operator Incident Response (GAO 2013)[17]
- 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 (ORNL 2012)

[13] Section 192.935(c) states, “If an operator determines, based on a risk analysis, that an ASV or 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 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.”

[14] Section 195.452(i)(4). If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors: the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.

[15] The Secretary has delegated this responsibility to the PHMSA Administrator. *See* 49 CFR 1.97.

[16] 75 FR 63774 (Oct. 18, 2010) (pertaining to hazardous liquid pipelines within docket PHMSA-2010-0229), and 76 FR 53086 (Aug. 25, 2011 (pertaining to natural gas transmission pipelines within docket PHMSA-2011-0023).

[17] GAO, “Pipeline Safety: Better Data and Guidance Needed to Improve Pipeline Operator Incident Response” (Jan. 2013), https://www.gao.gov/assets/660/651408.pdf.

- Leak Detection Study (Kiefner and Associates, Inc., 2012)[18]

In its 2013 study, the GAO concluded that PHMSA lacked available data to determine if pipeline operators respond in a "prompt and effective manner," as required in §§ 192.615(a)(3) and 195.402(e)(2), and cited these regulatory requirements as too vague to be accurately evaluated against collected response data from accident reports and investigations.[19] GAO also noted PHMSA has an opportunity to improve pipeline operator responses to incidents through a specific response time goal, but also recognized this may not be appropriate for all pipelines. GAO observed that operators could meet a standard for incident response by installing automated valves to reduce risks, and recommended better information sharing to help determine whether ASVs or RCVs would be the best option for meeting a response goal.

PHMSA commissioned ORNL to assess the effectiveness of block valve closure swiftness in mitigating the consequences of gas transmission and hazardous liquid pipeline releases. ORNL conducted feasibility evaluations and found in its ORNL 2012 report that "under certain conditions, installing ASVs and RCVs in newly constructed and fully replaced natural gas and hazardous liquid pipelines is technically, operationally, and economically feasible with a positive cost-benefit."[20] The report concluded that ASVs and RCVs are feasible if sufficient space is available for the valves and equipment. The report also found ASVs and RCVs are feasible if communication links between the RCV sites and the control rooms are continuous and reliable. ORNL concluded that ASVs and RCVs can be effective in mitigating potential fire consequences when releases ignite and can also be effective in mitigating potential socioeconomic and environmental damage resulting from releases that do not ignite.

PHMSA also gained insights from public fora, including:[21]

- Workshop on Leak Detection and Expanded EFRD Use (March 2012)
- Government and Industry Pipeline Research and Development Forum (July 2012)
- Webinar (October 2012) on the ORNL 2012 report and the Kiefner and Associates, Inc., 2012 study.

PHMSA considered all of this input in developing the subsequent February 2020 notice of proposed rulemaking (NPRM).[22]

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

[19] PHMSA began collecting operator incident response data in 2010, thus data collected since the GAO study should fill the data gap identified in that study.

[20] ORNL 2012 at page xxvii. ORNL 2012 also caveats this key finding with the following on the same paragraph: "However, these results may not apply to all newly constructed and fully replaced pipelines because site-specific parameters that influence risk analyses and feasibility evaluations often vary significantly from one pipeline segment to another, and may not be consistent with those considered in this study. Consequently, the technical, operational, and economic feasibility and potential cost benefits of installing ASVs and RCVs in newly constructed and fully replaced pipelines need to be evaluated on a case-by-case basis."

[21] Records from these meetings are available on PHMSA's public meetings web page at https://primis.phmsa.dot.gov/meetings/.

[22] 85 FR 7162 (Feb. 6, 2020).

1.2. FINAL RULEMAKING

The final rule establishes an installation and an operational standard for operator response to ruptures on certain new and entirely replaced natural gas and hazardous liquid onshore pipelines greater than or equal to 6 inches in diameter. Operators must be able to determine that a rupture has occurred and thereafter close all valves to isolate the rupture location as soon as practicable within 30 minutes of rupture identification (or, for hazardous liquid pipelines, the worst-case discharge shutoff time). Additionally, the final rule defines a rupture and requires certain safety program elements related to response and mitigation.

1.3. ORGANIZATION

The remainder of this document is organized as follows:

- **Section 2, Need for the Regulation**, provides justification for the final federal requirements;
- **Section 3, Description of the Final Rule and Alternative Approaches**, provides a summary of the final requirements and discussion of alternative approaches;
- **Section 4, Baseline for the Analysis**, summarizes existing requirements for rupture mitigation, potentially affected operators and infrastructure, and historical rupture incidents and consequences;
- **Section 5, Analysis of Costs**, provides analysis of the incremental compliance actions and costs;
- **Section 6, Analysis of Benefits**, provides analysis of the incremental benefits associated with the compliance actions;
- **Section 7, Limitations and Uncertainties**, discusses limitations and uncertainties underlying this analysis of the final rule;
- **Section 8, Evaluation of Alternatives,** provides an evaluation of regulatory alternatives to the final rule; and,
- **References**, provides a list of references.

2. NEED FOR THE REGULATION

This section discusses the need for the final revisions to the PSR. The final rule is applicable to certain (1) onshore natural gas transmission and regulated gas gathering (Type A only) pipelines, and (2) onshore hazardous liquid and regulated gathering pipelines, including carbon dioxide pipelines. Hereafter, we refer to these collectively as "gas pipelines" and "hazardous liquid pipelines," respectively.

2.1. PROBLEM DEFINITION

Section 4 of the Pipeline Safety Act of 2011 amends 49 U.S.C. 60102 to require the Secretary of Transportation, if appropriate, to "require by regulation the use of automatic or remote-controlled shut-off valves, or equivalent technology, where economically, technically, and operationally feasible on transmission pipeline facilities constructed or entirely replaced" after the date of the final rule containing the requirement. The existing PSR do not require a response time to isolate a ruptured line, nor do they explicitly require operators to use ASVs or RCVs. The mandate in the Pipeline Safety Act of 2011 followed closely on the heels of two incidents that highlighted the substantial and severe consequences of slow response times to pipeline ruptures and inadequate Federal requirements for operator response. The more time that elapses before a damaged section of a pipeline is isolated from the pipeline system, the greater the potential for damage. For gas pipelines, ignition of flammable gas is more likely the longer gas is released and after ignition fires can continue to be fueled as long as the release continues. For hazardous liquid pipelines, more hazardous liquid contamination can be spilled, which increases potential damages to the environment, the costs of clean up and remediation, and the risk to public safety.

Failure to detect and respond to pipeline ruptures in a prompt and effective manner results in damages that could otherwise be mitigated with more rapid response. In the September 2010 PG&E incident, the fires that followed, had devastating consequences. The blast and post-accident fires resulted in 8 fatalities, 51 injuries, 38 homes destroyed, and 70 homes damaged. Some of these consequences were caused by the continued burning of gas released after the rupture. The NTSB found that the pipeline operator, PG&E, took 95 minutes to isolate the rupture and stop the flow of gas. That delay increased the risk to residents and emergency responders and contributed to the severity and extent of property damage. Following investigation, the NTSB recommended that PHMSA amend § 192.935(c) to "directly require that automatic shutoff valves or remote control valves in high consequence areas and in Class 3 and 4 locations be installed and spaced at intervals that consider the factors listed in that regulation."

In July 2010 Enbridge incident, a hazardous liquid pipeline operated by Enbridge Energy ruptured in Marshall, MI, and released over 800,000 gallons of diluted bitumen into the Kalamazoo River and the surrounding wetlands for over 18 hours before being discovered, causing over $1.43 billion in costs, largely for environmental cleanup. The spill was eventually discovered and reported by a member of the public.

On May 19, 2015, Plains All American Pipeline, L.P.'s Line 901 ruptured near Santa Barbara, CA. It took the operator approximately 150 minutes to confirm the accident and contact the local emergency response agency after an operating anomaly was initially detected by a control room operator. As a result, 2,934 bbls of crude oil were released from Line 901, and a portion of the oil reached the Pacific Ocean near Refugio Beach, CA. Wind and water currents resulted in further oiling of the Pacific Ocean and shorelines and caused beach closures. The oil spill injured or killed numerous species of marine mammals, fish, birds, and other species and impacted important habitat. The operator reported spill liabilities in excess of $200 million from this accident.[23]

High-profile incidents like those described above usually trigger government intervention in their aftermath and result in new regulations to avoid future ones. PHMSA's final rule on installing ASVs and RCVs would improve pipeline safety by reducing the consequences of future incidents.[24]

The existing PSR do not require the isolation of a ruptured gas or hazardous liquid pipeline within a specific timeframe, nor do they explicitly require operators to use ASVs or RCVs. The existing PSR give a pipeline operator discretion to decide whether ASVs or RCVs are needed after performing a risk analysis. As noted in the NTSB report on the PG&E incident, a PG&E memorandum dated June 14, 2006 had concluded that the use of an ASV or an RCV as a prevention and mitigation measure in an HCA would have "little or no effect on increasing human safety or protecting properties."

In contrast to PG&E's conclusion on the use of an ASV or an RCV, the NTSB concluded that damage from the PG&E incident could have been reduced significantly if the valves on each end of the rupture point both had been ASVs or RCVs that could be closed rapidly. The NTSB also concluded that the use of ASVs or RCVs along the entire length of the affected pipeline would have significantly reduced the amount of time needed to isolate the rupture and stop the flow of gas. The incident report further notes that the existing integrity management regulations concerning ASVs and RCVs have not led to a meaningful increase in the installation and use of such valves on existing pipe, which was recommended following the Edison, NJ, incident (see section 1.1).

Only after the PG&E incident did the California Public Utilities Commission require that PG&E rapidly install ASVs. In 2006, PG&E had concluded that most of the damage from a rupture would take place in the first 30 seconds, before shutoff valves could stop the flow of gas.[25] Gas pipeline operators had previously cited a Gas Research Institute (1998) study as basis for concluding that installation of RCVs is not cost-effective because, in most cases, injury or death occurs so near to the time of pipeline rupture that RCVs may not respond quickly enough. The NTSB investigation of the 2010 PG&E incident and research by ORNL 2012, however, suggested that there are meaningful benefits to closing valves more rapidly and emergency

[23] Plains All American Pipeline, L.P., 2019 SEC 10-k filing.

[24] In comparison to PG&E's 95-minute response time during the PG&E incident, this rule proposes to require pipeline operators who have installed RMVs or alternative equivalent technologies under the final rule to isolate ruptured pipeline segments as soon as practicable, but not to exceed 30 minutes from rupture identification (or, in the case of hazardous liquid pipelines, the time to worst-case-discharge).

[25] Carey & Rogers, "PG&E Officials Grilled About Automatic Shut Off Valves," Mercury News (March 1, 2011), http://www.mercurynews.com/san-bruno-fire/ci_17510209?nclick_check=1.

response and PG&E seemed to concur, stating, "there is sufficient basis to deploy additional automatic valves."

Following the Enbridge accident, Enbridge also improved their capacity to quickly identify and isolate ruptures by remotely closing valves in response to corrective action and improvement plans.[26] Part of this response by Enbridge was compelled by a 2016 settlement of legal liabilities.[27] In addition to paying civil penalties of $62 million, Enbridge agreed to these measures:

- Implement an enhanced pipeline inspection and spill prevention program;
- Implement enhanced measures to improve leak detection and control room operations;
- Commit to additional leak detection and spill prevention requirements for a portion of Enbridge's Line 5 that crosses the Straits of Mackinac in Michigan;
- Create and maintain an integrated database for its Lakehead Pipeline System;
- Enhance its emergency spill response preparedness programs by conducting four emergency spill response exercises to test and practice Enbridge's response to a major inland oil spill;
- Improve training and coordination with state and local emergency responders by requiring incident command system training for employees, provide training to local responders, participate in area response planning and organize response exercises;
- Hire an independent third party to assist with review of implementation of the requirements in the settlement agreement.

These responses suggest that operators may have recognized that they had been undervaluing the consequences of unmitigated ruptures in IM risk decisions related to automated valves.

2.2. JUSTIFICATION FOR FEDERAL ACTION

Congress authorized Federal regulation of pipeline transportation of gas and hazardous liquids in the pipeline safety laws (49 U.S.C. chapters 601-603), a series of statutes that are administered by PHMSA. Congress established the current framework for regulating the safety of pipelines transporting gas in the Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90-481), and of pipelines transporting hazardous liquids in the Hazardous Liquid Pipeline Safety Act of 1979 (Pub. L. 96-129). These laws granted to DOT the authority to develop, prescribe, and enforce minimum Federal safety standards for the transportation of gas and hazardous liquids by pipeline. PHMSA is the agency within DOT that administers the PSR. PHMSA has codified a set of comprehensive safety standards for the design, construction, testing, operation and

[26] https://www.enbridge.com/~/media/Enb/Documents/Factsheets/FS_WhatsChangedSinceMarshall.pdf
[27] https://www.justice.gov/opa/pr/united-states-enbridge-reach-177-million-settlement-after-2010-oil-spills-michigan-and.

maintenance of pipelines in 49 CFR part 192, Transportation of Natural and Other Gas by Pipeline, and in 49 CFR part 195, Transportation of Hazardous Liquids by Pipeline.

Following the PG&E incident in 2010, Congress amended 49 U.S.C. 60102 to require DOT to, if appropriate, "require by regulation the use of automatic or remote control shut-off valves, or equivalent technology, where economically, technically, and operationally feasible, on newly constructed or entirely replaced hazardous liquid and natural gas transmission pipeline facilities." The Pipeline Safety Act of 2011 also required a study of operator response capabilities to hazardous liquid and gas pipeline releases in HCAs, including consideration of the swiftness of leak detection and pipeline shutdown capabilities, the location of the nearest response personnel, and the costs, risks, and benefits of installing automatic and remote-controlled shut-off valves.

As described in Section 1.2 above, PHMSA considered the studies commissioned pursuant to the Pipeline Safety Act of 2011 (i.e., Kiefner and Associates, 2012 and ORNL 2012), as well as the GAO 2013 study. The independent risk analysis conducted in ORNL 2012 indicates that rapid emergency response to ruptures and line isolation can limit or prevent harmful consequences from gas and hazardous liquid pipeline ruptures. For gas transmission ruptures, ORNL 2012 modeled the potential consequences of simulated incidents in HCAs due to fire damage varying by duration until valve closure, class location, diameter, and other parameters. Similarly, for hazardous liquids, the ORNL 2012 study estimated the spill volume for various duration, diameter, and pressure scenarios. The analysis shows that pipeline operators can avoid significant consequences for hazardous liquid pipelines and large-diameter gas pipelines located in densely populated areas.

3. DESCRIPTION OF THE FINAL RULE AND ALTERNATIVE REGULTORY APPROACHES

This section provides a summary of the final rule and potential alternative regulatory approaches.

3.1. FINAL RULE

Table 3-1 provides a summary of the final regulatory changes applicable to onshore gas pipeline and hazardous liquid pipeline regulations, respectively, as briefly discussed below.

Table 3-1. Summary of Final Amendments to 49 CFR Parts 192 and 195

Section	Description
Gas Pipelines	
192.3	Defines “RMV,” "entirely replaced onshore pipeline segments," and “notification of potential rupture.”
192.9	Clarifies the exclusion of gas distribution lines from parts of the final rule’s amendments.
192.18	Provides for notification of PHMSA for operators’ intent to use an alternative equivalent technology, or a method that differs from that listed in the regulations.
192.179	Requires all valves on newly constructed or entirely replaced onshore transmission and Type A gathering lines greater than or equal to 6 inches in diameter to be ASVs, RCVs, or alternative equivalent technology that can meet the standards in § 192.636 and isolate a ruptured pipeline segment as soon as practicable, but within 30 minutes of rupture identification. Class 1 or Class 2 locations that have a PIR less than or equal to 150 feet are excluded.
192.610	Establishes applicability of § 192.636 if a change in class location on a transmission pipe results in pipe replacement. If an operator replaces less than 2 miles of pipe in a length of 5 contiguous miles of pipe during a 24-month period to comply with the maximum allowable operating pressure requirements after a class location changes, the operator must either: (1) comply with the valve spacing requirements at § 192.179(a) or (2) install or use RMVs so that the entirety of the replaced pipeline segment is between two RMVs and so that the distance between those valves does not exceed 20 miles. Operators are not required to comply with this section if they replace less than 1,000 feet of pipe within a single contiguous mile within a 24-month period to comply with a class location change.
192.615	Requires 9-1-1 emergency call center notification, local information specificity, and also requires operators to develop written procedures to evaluate and identify whether notifications of potential ruptures are actually ruptures after notification. At a minimum, the procedures must specify the sources of information, operational factors, and other criteria that the operator will use to evaluate a notification of potential rupture as an actual rupture.
192.617	Adds specificity for post-incident/failures investigation procedures and lessons learned; requires analysis of incidents where rupture identification and operation of RMV and alternative equivalent technology occurred.
192.634	Establishes maximum spacing requirements between RMVs/alternative equivalent technology, as well as application of those spacing requirements to different pipeline configurations (e.g., laterals, and crossovers).
192.635	Establishes indicia of a potential rupture referenced in the definition of “notification of potential rupture” in § 192.3.
192.636	Establishes emergency operations standard requiring operators installing RMVs or alternative equivalent technology pursuant to the final rule to isolate ruptured pipeline segments as soon as practicable with complete segment isolation within 30 minutes of rupture identification. Applicable to onshore transmission and gathering pipeline segments 6 inches or greater in diameter in HCAs, Class 3, or Class 4 locations that are newly-constructed or where 2 or more contiguous miles have been replaced. For Class 1 and Class 2 locations, segments with a PIR less than or equal to 150 feet are excluded. Establishes valve monitoring and operation capabilities.

Table 3-1. Summary of Final Amendments to 49 CFR Parts 192 and 195	
Section	**Description**
192.745	Prescribes testing requirements for RMVs, as well as maintenance, inspection, and drills requirements for alternative equivalent technologies to ensure operators can close those technologies within 30 minutes. Operators must identify corrective actions and lessons learned from drills and implement them across its entire network of pipeline systems.
192.935	Clarifies the requirements for conducting RMV and alternative equivalent technology evaluations for HCAs, particularly when an operator installs such valves as preventive and mitigative measures to improve response times for pipeline ruptures and mitigate the consequences of a rupture. Valves installed in accordance with this section must meet all other RMV requirements in part 192. Also, requires that risk analyses and assessments conducted under this section be annually reviewed by the operator. Such analyses and assessments must consider new or existing operational and integrity matters that could affect rupture-mitigation processes and procedures.
Hazardous Liquid Pipelines	
195.2	Defines “RMV,” "entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments," and “notification of potential rupture.”
195.11	Excludes certain regulated rural gathering lines from the scope of the final rule’s amendments.
195.18	Provides for notification of PHMSA for operator’s intent to use an alternative equivalent technology, or a method that differs from that listed in the regulations.
195.258	Requires RMVs or alternative equivalent technology on newly constructed and entirely replaced hazardous liquid transmission and gathering pipelines greater than or equal to 6 inches in diameter. For rural gathering lines, the RMV regulations only apply to those lines that cross water bodies greater than 100 feet in width. The requirements apply only to new or entirely replaced pipeline projects affecting valves. The RMVs or alternative equivalent technology must be spaced in accordance § 195.260, installed in accordance with this section and meet the operational requirements of § 195.419. Alternative equivalent technology installations must be reported in accordance with § 195.418.
195.260	Establishes maximum valve spacing on newly constructed and entirely replaced pipelines of 20 miles for pipelines outside HCAs, 15 miles for pipelines in HCAs, and 7.5 miles for HVL (highly-volatile liquid) pipelines in populated areas. The HCA valve locations must be determined through the operator’s process for identifying preventive and mitigative measures established pursuant to § 195.452(i) and Appendix C of part 195.
195.402	Requires operators to have procedures to identify areas requiring an immediate response by the operator, including segments that are in HCAs or that could affect HCAs and segments with valves that are specified in §§ 195.418 and 195.452. Defines elements that an operator must incorporate when conducting a post-accident analysis of ruptures and other release and failure events involving the activation of rupture-mitigation valves. The operator must develop and implement the lessons learned throughout its suite of procedures. Requires that emergency procedures provide for rupture detection and valve closure in response to a leakage or failure event, including specific timing provisions relating to ruptures, and establishing and maintaining adequate means of communication with the appropriate public safety answering point (i.e., 9-1-1 emergency call center).
195.417	Establishes indicia of a potential rupture referenced in the definition of “notification of potential rupture” in § 195.2.
195.418	Establishes installation and spacing requirements for RMVs and alternative equivalent technologies. Applies to newly constructed, entirely replaced, and replacements of 2 or more miles of onshore pipelines greater than or equal to 6 inches in diameter in HCAs. Operators must designate shut-off segments in these areas and designate mainline valves used to isolate ruptures as RMVs. Establishes maximum distances between RMVs of 7.5 miles for HVL pipelines and 15 miles otherwise and requires pressure monitoring of all RMVs.
195.419	Establishes operational requirements that RMVs and alternative equivalent technologies installed under the final rule are required to meet. RMVs and alternative equivalent technologies must close as soon as practicable, within the earlier of 30 minutes from rupture identification and any §

Table 3-1. Summary of Final Amendments to 49 CFR Parts 192 and 195	
Section	**Description**
	194.105(b)(1) worst-case discharge shut-off time. RMVs must be capable of being monitored or controlled by remote or on-site personnel, operated during all operating conditions, and monitored for valve status. Operators of pipelines in non-HCAs or of segments that could not affect an HCA can request an exemption from some of the requirements.
195.420	Requires maintenance, inspection, and operator drills to ensure operators can close RMVs and alternative equivalent technologies installed under § 195.258 within 30 minutes. Operators must identify corrective actions and lessons learned from drills and implement them across its entire network of pipeline systems.
195.452	Clarifies the requirements for conducting RMV and alternative equivalent technology evaluations for HCAs, particularly when an operator installs such valves as preventive and mitigative measures to improve response times for pipeline ruptures and mitigate the consequences of a rupture. Valves installed in accordance with this section must meet all other RMV requirements in part 195. Also, requires that risk analyses and assessments conducted under this section be annually reviewed by the operator.
HCA = high consequence area HVL = highly volatile liquid SCADA = supervisory control and data acquisition	

3.1.1. Definition of Conditions for the Notification of Potential Ruptures

For both natural gas and hazardous liquid pipelines, the final rule defines "notification of potential rupture" as any of the following events that are indications of an unintentional or uncontrolled release from a pipeline:

1. An unanticipated or unexplained pressure loss outside of the pipeline's normal operating pressures, as defined in the operator's written procedures. For hazardous liquid pipelines, the operator observes an unanticipated or unplanned flow rate change of 10 percent or greater or a pressure loss of 10 percent or greater outside of the pipeline's normal operating pressures, as defined in the operator's written procedures;
2. A release of a large volume of commodity, a fire, or an explosion, in the immediate vicinity of the pipeline; or
3. An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station.

3.1.2. Requirement for RMVs

For both natural gas and hazardous liquid pipelines, the final rule requires the valves on new and entirely replaced onshore lines greater than 6 inches in diameter to be ASVs, RCVs, or alternative equivalent technology. For gas pipelines, pipe segments in Class 1 or Class 2 locations that have a PIR less than or equal to 150 feet and Type B gas gathering pipelines are excluded. These valves must meet the operational standards and isolate a ruptured pipeline segment as soon as practicable, but not later than within 30 minutes of rupture identification.

3.1.3. Operational Requirements

The final rule establishes an emergency operations standard requiring operators to close RMVs and alternative equivalent technologies installed pursuant to the final rule on certain ruptured onshore pipeline segments as soon as practicable, but no more than within 30 minutes of rupture identification (or, for hazardous liquid pipelines, before the shutoff time for worst-case discharge).

The final rule establishes maximum distances between RMVs and alternative equivalent technologies from 8 to 20 miles, depending on class location, for gas pipelines (§§ 192.179(h) and 192.636(b)(2)), and 15 miles for hazardous liquid pipelines or 7.5 miles for HVL pipelines (§ 195.260(c)). Compliance with the standard can be achieved using ASVs, RCVs, or alternative equivalent technology (with notification to PHMSA). The final rule also requires that operators monitor the position and operational status of RMVs and alternative equivalent technology, however ASVs do not need to be monitored if the capability to identify and locate a rupture is available on the pipeline. Operators are required to meet these provisions for new pipeline construction or replacement projects that are completed more than 12 months after the publication date of the final rule.

For locally operated valves (i.e., operator personnel operate the valve at the valve site), the operator must conduct annual drills to validate compliance for a sample of valves. Operators have to assess the effectiveness of their rupture-mitigation performance when a rupture occurs or whenever any event involves RMV or alternative equivalent technology closure. Operators must take corrective actions as needed to improve their responses to and mitigation of ruptures, and to evaluate which, if any, of those corrective actions or improvements need to be implemented elsewhere in their pipeline networks.

3.2. ALTERNATIVE REGULATORY APPROACHES

With the final rule, PHMSA is addressing the mandate in the Pipeline Safety Act of 2011 to require by regulation use of automatic or remote-controlled shut-off valves, or alternative equivalent technology, where economically, technically, and operationally feasible. In doing so, the Pipeline Safety Act of 2011 specifies that PHMSA consider the factors in 49 U.S.C. 60102, which include considering relevant available safety and environmental information; appropriateness and reasonableness; and benefits and costs, based on a risk assessment. The response-time standard in this final rule meets the intent of the Pipeline Safety Act of 2011 by enforcing minimum response time regardless of the choice in valve technology.

ORNL 2012 evaluated the technical, operational, economic feasibility, potential costs, and benefits of installing ASVs and RCVs in newly constructed and replaced transmission lines. Specifically, ORNL conducted risk analyses of hypothetical pipeline release scenarios to assess: (1) fire damage to buildings and property in Class 1, Class 2, Class 3, and Class 4 HCAs that is caused by natural gas pipeline releases and subsequent ignition of the released natural gas; (2) fire damage to buildings and property in HCAs designated as high population areas and other populated areas caused by hazardous liquid pipeline releases and subsequent ignition of the released propane; and (3) socioeconomic and environmental damage in HCAs caused by hazardous liquid pipeline releases of crude oil. These risk analyses used engineering principles and fire science practices to characterize thermal radiation effects on buildings and humans, and to quantify the total damage cost of socioeconomic and environmental impacts for typical failure scenarios. For gas pipeline ruptures, damages were found to result from the initial blast and accumulate as long as gas is emitted increasing the probability of ignition and fire damage of nearby property. The property damage worsens and firefighting is hindered with continued exposure to the gas flame. Depending on the characteristics of the pipeline, the location of the rupture and the reduction in valve closure times, avoided damages can be in the millions (see Section 6.1). For hazardous liquid pipelines, more rapid valve closure after rupture was found to result in reduced spill sizes, and thus lower cleanup costs as described in Section 6.2.

ORNL 2012 found the feasibility evaluations for the hypothetical pipeline release scenarios show installing ASVs and RCVs in newly constructed and replaced natural gas and hazardous liquid pipelines is technically, operationally, and economically feasible with positive net benefits (i.e., benefits minus costs). However, these results may not apply to all newly constructed and replaced pipelines because site-specific parameters that influence risk analyses and feasibility evaluations often vary significantly from one pipeline segment to another and may not be consistent with those considered in this study. Consequently, the technical, operational, economic feasibility, potential costs, and potential benefits of installing ASVs and RCVs in newly constructed or replaced pipelines need to be evaluated on a case-by-case basis. Installing ASVs and RCVs in pipelines can be an effective strategy for mitigating potential consequences of unintended releases because decreasing the total volume of the release reduces overall impacts on the public and to the environment.

These findings suggest potential alternative approaches to the scope of the requirements. Based on the ORNL 2012 finding that installing ASVs and RCVs may need to be evaluated on a case-by-case basis, the final rule establishes an RMV operation performance standard and allows alternative equivalent technology. Additionally, the modeling in ORNL 2012 suggests that the benefits of valve automation scale significantly with pipe diameter. PHMSA therefore considered a larger pipeline diameter cutoff for gas pipelines but decided against this option because it would have excluded pipelines that could have a significant impact on dwellings in vicinity of a rupture. Instead, PHMSA used a PIR criterion for gas pipelines in Class 1 and Class 2 locations that cuts off the regulated diameter depending on operating pressure. PHMSA also considered expanding the applicable scope of gas gathering pipelines to Type B also; and limiting the scope to include HCA segments in Class 1 and Class 2 locations.

PHMSA also attempted to address related recommendations from the NTSB to the extent possible under this rulemaking mandate, with the final rule, as noted in Section 1.1.

4. BASELINE FOR THE ANALYSIS

This section describes the baseline for measuring the incremental impact of the final rule, including potentially affected entities, existing regulatory requirements, frequency of pipeline ruptures, and consequences of pipeline ruptures.

4.1. POTENTIALLY AFFECTED ENTITIES

The final rule primarily applies to the design of newly constructed pipelines, which could include all current pipeline operators. Based on annual report data, PHMSA identified 1,304 gas pipeline operators and 508 hazardous liquid pipeline operators with pipelines that will be subject to these new requirements (Table 4-1).

Table 4-2 summarizes 2015 to 2019 average pipeline construction mileage that will be subject to the final rule. PHMSA assumed that future pipeline installations continue at the historical rate in this analysis.

Table 4-1. Number of Potentially Affected Entities

System Type	Operators of Onshore Transmission and Gathering Pipelines[1]
Gas pipelines	1,304
Hazardous liquid pipelines	508

Source: PHMSA Annual Report data. The 2020 report is the latest available for gas pipelines and the 2019 report is the latest available for hazardous liquid pipelines.
1. Represents number of operator identifications (OPID). An OPIDs may be associated with both gas and hazardous liquid pipelines.

Table 4-2. New Pipeline Construction (Miles)

Pipeline System Type	Five-Year Annual Average Miles
Hazardous Liquid Transmission (incl. CO_2)	2,175
Hazardous Liquid Gathering[1]	198
Hazardous Liquid Subtotal	***2,373***
Gas Transmission	3,013
Gas Gathering[2]	110
Gas Subtotal	***3,123***
Total	**5,556**

Source: PHMSA Annual Report data (https://primis.phmsa.dot.gov/construction/index.htm). Due to data availability, the five-year period for gas pipelines is 2016 to 2020 and for hazardous liquid pipelines is 2015 to 2019.
1. Includes 155 miles per year of non-rural, and 43 miles per year of rural gathering lines.
2. Includes Type A and Type B gathering

4.2. REGULATORY FRAMEWORK

Regulations that can require use of RMVs only exist for specific limited circumstances, so the final rule will expand on those requirements. The current PSR require operators to identify pipeline threats, conduct risk assessments, and take additional measures as necessary to mitigate the consequences of possible pipeline failures in HCAs. Both the natural gas and hazardous liquid integrity management (IM) regulations address valve installation and incident response in HCAs. In December 2000, PHMSA published a final rule establishing hazardous liquid IM regulations and requiring operators of pipelines in HCAs to equip these lines with a "means to detect leaks" to protect the HCA.[28] Similarly, in 2003, PHMSA issued a final rule requiring gas operators to install ASVs or RCVs if it "would be an efficient means of adding protection to a high consequence area in the event of a gas release."[29] Also, hazardous liquid pipelines require installation of an EFRD if doing so "is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release."[30]

The NTSB found in investigating the PG&E incident that these standards, as they relate to gas pipelines, have proven to be inadequate. The NTSB determined that, because the existing standard lacks clear technology or performance requirements, "there is little incentive for an operator to perform an objective risk analysis" in accordance with § 192.935(c). As a result, the NTSB recommended that PHMSA explicitly require ASVs or RCVs in HCAs and Class 3 and 4 locations (P-11-11).

In 2013, the GAO surveyed 8 operators regarding their risk management decisions related to the existing ASV and RCV installation requirements. Table 4-3 presents a summary of these operators' risk analysis practices and the results.

Table 4-3 . Results of GAO Survey of How Operators Determine Whether to Install Automated Valves

Operator (System Type)	Miles Analyzed and Results	Stated Costs	Rationale
Belle Fourche (hazardous liquid)	460 (135 HCA); no installations	\$100,000 to \$500,000 to install RCV	Use spill modeling software that considers rates, pressure, terrain, product type, and waterways to determine release quantity and extent of damages; consider costs including communications equipment and access to valve if don't own right-of-way (ROW)
Buckeye Partners (hazardous liquid)	6,400 (4,179 could affect HCA); additional analysis of possible RCV installation on 25 out 75 segments	\$35,000 to \$325,000	Use spill modeling software to determine release quantity and damages; consider installations if decrease release quantity by 50 percent or more or significantly reduce damages; consider costs including access if don't own ROW
Phillips 66 (hazardous liquid)	11,290 (3,851 could affect HCA); 71 automated valves in 508 locations assessed	\$250,000 to \$500,000	Use spill modeling software to determine release quantity and extent of damages; consider automated valves if drain volume could exceed 1,000 barrels, consequences meet a threshold valve, and existing automated valves are greater than 7.5 miles apart; consider costs including

[28] See 65 FR 75378, codified at § 195.452(i)(3).
[29] See 68 FR 69778, codified at § 192.935.
[30] See 49 CFR 195.452 (i)(4).

Table 4-3 . Results of GAO Survey of How Operators Determine Whether to Install Automated Valves			
Operator (System Type)	**Miles Analyzed and Results**	**Stated Costs**	**Rationale**
			communications, power, access if don't own ROW, and local construction costs
Enterprise Products (hazardous liquid; natural gas)	23,012 (8,783 could affect HCA); no installations	$250,000 to $500,000	Use spill modeling software that considers topography and placement of existing valves to determine release quantity (do not consider gas or HVL lines), and extent of damages; risk algorithm to identify threats to pipeline segments; and consider costs including communications and amount of necessary infrastructure work
Granite State (natural gas)	86 (11HCA); installation of RCVs on 30 out of 30 locations	$40,000 to $50,000	Use risk analysis software that considers response time to incident, population in area, pipe diameter, and other variables; consider costs including communications equipment and modifications to leak detection system
Kinder Morgan Natural Gas Pipeline Company of America (natural gas)	9,800 (569 HCA); 683 ASVs installed out of 832 locations with remainder planned	$48,000 to $100,000 to install ASV on existing manual valve	Long-term risk management strategy regardless of advantages/disadvantages on any one segment; do not consider costs
Northwest Pipeline GP (natural gas)	3,900; (170 HCA); installed automated valves at 59 of 730 locations assessed	$37,000 to $240,000	Use decision tree based on factors such as location of the valve, pipe diameter, and Response time; will install automated valve in any HCA, Class 3, or Class 4 on large diameter pipe (>12") where personnel cannot close the valve in under an hour; consider costs in terms of most cost-effective way to ensure response within one hour in HCAs
Williams Gas Pipeline-Transco	11,000; 1,192 (HCA); installed automated valves at 56 of the 2,461 locations assessed	$75,000 to $500,000	Uses decision tree based on factors such as location of valve, pipe diameter, and response time; will install an automated valve in any HCA, Class 3, or Class 4 large diameter pipe (>12") where personnel cannot close the valve in under an hour; consider costs in terms of most cost-effective way to ensure response within one hour in HCAs
Source: GAO (2013) ASV = automatic shut off valve HCA = high consequence area HVL = highly volatile liquids RCV = remote control valve ROW = right of way			

Existing emergency response regulations address operational responses to all incidents, including ruptures. Both gas and hazardous liquid operators are required to contact emergency response agencies as soon as possible following the identification of a pipeline accident. And under 49

CFR part 194, operators of onshore hazardous liquid pipelines must prepare response plans to reduce the environmental impact of oil discharges and operate their pipelines in accordance with such plans. These plans include spill detection and mitigation procedures and a drill program for emergency response exercises.

The final rule will require operators to modify emergency response plans to specify methodologies for confirming a rupture on notification of potential rupture. Operators of pipelines on which an RMV or alternative equivalent technology has been installed pursuant to the final rule must identify ruptures and shutdown pipelines as soon as practicable, and in a time period not to exceed 30 minutes after rupture identification (or, for hazardous liquid pipelines, within the worst case discharge valve closure time).

4.3. FREQUENCY AND CONSEQUENCES OF RUPTURES

Table 4-4 shows the number of onshore gas transmission pipeline mechanical punctures and physical ruptures (punctures often have the same release characteristics as ruptures) and the associated consequences. These incidents are reportable incidents on both transmission lines and the smaller mileage of regulated gas gathering lines (Types A and B). Reported consequences include, but are not limited to, the potential for injuries and fatalities; costs due to property damage, including damage to operator facilities and the property of others; facility repair and replacement; emergency response; and environmental damage, including cleanup and remediation. Operators must file supplemental reports to update these costs as new cost information becomes available and if costs differ from those already reported by 20 percent or $20,000, whichever is greater. Therefore, the information may be preliminary.

Table 4-4. Onshore Gas Transmission Pipeline Incidents and Reported Consequences

Year	Number of Incidents[1]			Number of Fatalities	Number of Injuries	Number of Individuals Evacuated	Release Volume (MCF)[4]	Property and Environmental Damages[2]
	Total[3]	Class 3	HCA					
2002	20	1	1	1	1	72	985,399	$9,759,599
2003	21	2	1	0	1	375	2,287,036	$24,560,053
2004	23	2	2	0	0	300	511,467	$3,663,166
2005	20	2	1	0	0	1,058	1,694,842	$116,540,540
2006	18	3	1	3	0	324	972,959	$4,958,617
2007	27	3	2	1	4	569	2,450,512	$21,724,151
2008	15	3	0	0	1	304	871,082	$12,307,425
2009	23	5	2	0	6	525	726,898	$20,602,040
2010	27	1	1	10	58	156	1,262,734	$669,528,413
2011	28	3	3	0	0	18	781,122	$57,293,620
2012	30	5	3	0	2	554	1,477,625	$12,913,341
2013	30	4	1	0	2	2,986	747,541	$12,172,548
2014	31	3	1	0	0	596	744,845	$23,979,920
2015	35	5	2	2	15	421	985,760	$28,938,945
2016	26	4	2	1	2	790	1,339,331	$85,168,789

Table 4-4. Onshore Gas Transmission Pipeline Incidents and Reported Consequences								
Year	Number of Incidents[1]			Number of Fatalities	Number of Injuries	Number of Individuals Evacuated	Release Volume (MCF)[4]	Property and Environmental Damages[2]
	Total[3]	Class 3	HCA					
2017	16	0	0	2	2	130	759,264	$15,380,813
2018	27	8	3	1	4	62	842,782	$42,980,273
2019	20	3	1	0	2	358	422,869	$34,666,826
2020	27	6	4	0	1	161	652,273	$38,857,416
Total	465	63	N/A	21	101	9,759	N/A	$1,235,996,496
Annual Average 2002-2020	24	3	N/A	1	5	514	N/A	$65,052,447

Source: PHMSA Gas Transmission & Gathering Incident Data - January 2010 to present and Gas Transmission & Gathering Incident Data - 2002 to December 2009. The information may be updated as new information becomes available.
Note: Detail may not add to total due to rounding.
HCA = high consequence area
1. Incidents for which operators reported the leak type as physical rupture or mechanical puncture.
2. Does not include the cost of lost gas. Constant dollars at the 2020 price level.
3. Eighteen of 298 incidents between 2010-2020 that PHMSA has further examined were isolated by ASVs and/or RCVs. Of these, 10 were isolated with ASVs upstream and downstream, 7 were isolated with RCVs upstream and downstream, and 1 was isolated with an ASV upstream and an RCV downstream.
4. Estimate of release for 2009 and earlier using reported value of gas loss divided by average Henry Hub Natural Gas Spot Price for report year (https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm).

These incidents include the 2010 PG&E incident, which is the most destructive gas transmission pipeline incident in recent history.

In Table 4-5, damages from the same gas transmission and gathering pipeline incidents listed in Table 4-4 are totaled in subcategories of those incidents in HCAs and those in the four class locations for the years 2002 to 2020. Estimated damages are large for incidents on pipelines in Class 1 locations both because of the large fraction of the onshore transmission and regulated gas gathering pipeline system mileage (75% in 2020) in Class 1 and possibly because of the less stringent safety standards for the designation (despite the fact that Class 1 locations, by definition, are not in close proximity to populations and structures which could sustain costly damages). In contrast, regulated gas gathering and transmission line mileage in Class 4 locations is much less extensive (0.3% of the pipeline system in 2020) and subject to more stringent safety standards, yet only one incident was recorded from 2002 to 2020. The damage totals for HCAs and Class 3 locations are large because of the PG&E incident in 2010, which entailed damages of $659.6 million (in 2020 dollars); that incident involved a transmission pipeline which was in an HCA that was also a Class 3 location. If the PG&E incident were excluded, the total damages on Class 3 are much smaller, reflecting the smaller proportion of the pipeline system (7% HCA and 12% Class 3 in 2020) and the more stringent regulation of those lines given their closer proximity to population and property. PHMSA submits, however, that exclusion of the PG&E incident would be inappropriate. The PG&E incident represents precisely the sort of low-probability, high-consequence (LPHC) event whose prevention is the object of much of PHMSA's regulatory oversight activity, including this final rule. Those events can be captured in longer analysis periods but risk neglection over shorter analysis periods—even as the risk of an LPHC event exists throughout the period even in years when such an event does not occur.

Table 4-5. Onshore Gas Transmission Pipeline Incident Property and Environmental Damages

Year	HCA	Class 1	Class 2	Class 3	Class 4	All Incidents
2002	$2,200,682	$7,935,883	$1,823,382	$334	0	$9,759,599
2003	$21,058	$23,855,394	$458,026	$246,633	0	$24,560,053
2004	$202,264	$2,934,113	$64,663	$468,824	$10,293	$3,663,166
2005	$1,168,894	$115,314,941	$1,168,894	$17,743	0	$116,540,540
2006	$566,953	$2,544,322	$839,426	$1,461,479	0	$4,958,617
2007	$913,923	$20,691,234	$76,058	$956,859	0	$21,724,151
2008	0	$11,149,026	$830,042	$328,358	0	$12,307,425
2009	$12,157,249	$5,266,720	$53,820	$15,281,500	0	$20,602,040
2010	$659,555,948	$10,183,878	$201,845	$659,555,948	0	$669,528,413
2011	$205,822	$55,563,024	$3,890,479	$205,822	0	$57,293,620
2012	$948,948	$6,752,321	$4,880,725	$1,743,184	0	$12,913,341
2013	$72,794	$9,721,013	$669,201	$2,195,770	0	$12,172,548
2014	$62,495	$16,803,218	$7,151,772	$978,120	0	$23,979,920
2015	$6,520,224	$22,231,859	$49,645	$7,544,041	0	$28,938,945
2016	$204,784	$85,459,017	$175,518	0	0	$85,168,789
2017	0	$9,062,826	$6,955,364	$2,886,934	0	$15,380,813
2018	$553,875	$33,052,859	$3,181,198	$8,188,000	0	$42,980,273
2019	$249,575	$35,220,922	$444,874	$420,202	0	$34,666,826
2020	$8,857,689	$27,601,653	$113,480	$12,245,091	0	$38,857,416
Total	$694,463,177	$501,344,221	$33,028,412	$695,963,111	$10,293	$1,235,996,496

Source: PHMSA Gas Transmission & Gathering Incident Data - January 2010 to present and Gas Transmission & Gathering Incident Data - 2002 to December 2009. The information may be updated as new information becomes available.
Note: Detail may not add to total due to rounding.
HCA = high consequence area
Incidents for which operators reported the leak type as physical rupture or mechanical puncture.
Does not include the cost of lost gas. Constant dollars at the 2020 price level.

Table 4-6 shows statistics for hazardous liquid pipelines. Some environmental costs, including long-term remediation and/or monitoring which is being conducted under the auspices of an authorized governmental agency or entity, may not be captured in PHMSA's data.[31] For

[31] Per PHMSA instructions for the hazardous liquid accident reporting, an operator may cease filing supplemental reports and, instead file a final report, even when additional remediation costs are still occurring when the accident response consists only of long-term remediation and/or monitoring which is being conducted under the auspices of an authorized governmental agency or entity.

example, the final report for the 2013 Tesoro pipeline spill in North Dakota (report number 20130353) declares total costs of $17.8 million. Per recent reporting, cleanup costs could top $100 million for the company (MacPherson, 2017).[32]

Table 4-6. Onshore Hazardous Liquid Pipeline Accidents and Reported Consequences[1]

Year	Number of Accidents[2]	Number of Fatalities	Number of Injuries	Number of Individuals Evacuated	Release Volume (bbls)	Property and Environmental Costs[3]
2002	11	0	0	36	49,851	$16,933,490
2003	11	0	0	510	21,466	$39,275,973
2004	13	0	0	75	19,593	$36,487,759
2005	12	0	1	200	25,920	$46,248,526
2006	7	0	2	8	37,829	$29,595,742
2007	8	2	7	227	46,119	$21,538,260
2008	8	0	0	20	47,120	$25,284,181
2009	6	0	0	0	5,878	$6,639,420
2010	27	1	1	102	62,004	$1,028,047,909
2011	24	0	0	115	23,181	$26,442,216
2012	24	0	0	229	27,292	$82,507,491
2013	24	1	0	815	68,312	$152,626,753
2014	18	0	0	32	18,190	$26,045,300
2015	26	0	0	8	76,672	$25,802,242
2016	18	3	5	65	29,194	$41,739,975
2017	19	0	0	3	28,385	$65,073,457
2018	31	0	2	158	99,738	$77,739,878
2019	13	0	0	0	35,451	$63,432,488
2020	15	5	5	98	34,268	$13,930,226
Total	315	12	23	2,701	756,459	$1,825,391,287
Annual Average 2002-2020	22	1	1	148	45699	$96,073,226

Source: PHMSA Hazardous Liquid Accident Data - January 2010 to present and Hazardous Liquid Accident Data - January 2002 to December 2009. The information may be updated as new information becomes available.
Note: Detail may not add to total due to rounding.
HCA = high consequence area
1. Accidents for which operators reported the failure type as a physical rupture or mechanical puncture.
2. Fifty-five of 244 incidents between 2010-2020 PHMSA has further examined were isolated by ASVs and/or RCVs and/or downstream check valves. Of these, 12 were isolated with ASVs upstream and downstream, 39 were isolated with RCVs upstream and downstream, and 4 were isolated with an RCV upstream and check valve downstream.
3. Does not include value of commodity loss. May not include long term remediation costs. See Instructions (rev 12-2015) for Form PHMSA F 7000-1 (rev 7-2014) ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS, p. 5. Constant dollars at the 2020 price level.

[32] MacPherson, "4 Years Later, Cleanup Nears End for Big North Dakota Spill" StarTribune (Sept. 15, 2017), http://www.startribune.com/4-years-later-cleanup-nears-end-for-big-north-dakota-spill/444714133/.

Damages from hazardous liquid pipeline accidents in HCAs are totaled by year from 2002 to 2020 in Table 4-7. Similar to the gas incidents, the pattern of these damages is affected by an LPHC event: the 2010 Enbridge accident that incurred damages of $993.3 million (in 2020 dollars). HCA hazardous liquid pipelines represented 43% of the hazardous liquid pipeline mileage nationwide in 2020. Incidents in HCAs amounted to 82% of the damages over the same period when the Enbridge accident is included and 61% when that accident is excluded from the data set.

Table 4-7. Onshore Hazardous Liquid Pipeline Accident Property and Environmental Costs

Year	HCA	All Accidents
2002	$15,596,300	$16,933,490
2003	$33,454,914	$39,275,973
2004	$30,417,855	$36,487,759
2005	$41,326,932	$46,248,526
2006	$23,053,896	$29,595,742
2007	$14,893,412	$21,538,260
2008	$16,842,835	$25,284,181
2009	$4,802,803	$6,639,420
2010	$996,633,728	$1,028,047,909
2011	$20,806,748	$26,442,216
2012	$36,892,770	$82,507,491
2013	$128,413,037	$152,626,753
2014	$20,354,957	$26,045,300
2015	$14,369,954	$25,802,242
2016	$28,434,519	$41,739,975
2017	$2,266,611	$65,073,457
2018	$53,874,549	$77,739,878
2019	$10,626,997	$63,432,488
2020	$10,452,797	$13,930,226
Total	$1,503,515,617	$1,825,391,287

Source: PHMSA Hazardous Liquid Accident Data - January 2010 to present and Hazardous Liquid Accident Data - January 2002 to December 2009. The information may be updated as new information becomes available.
Note: Detail may not add to total due to rounding.
HCA = high consequence area
Accidents for which operators reported the failure type as a physical rupture or mechanical puncture.
Does not include value of commodity loss. May not include long term remediation costs. See Instructions (rev 12-2015) for Form PHMSA F 7000-1 (rev 7-2014) ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS, p. 5. Constant dollars at the 2020 price level.

4.4. VALVE AUTOMATION

Regulatory filings for new pipeline projects indicate the widespread use of RCVs. PHMSA used this information to establish anticipated rates of use for remote-operated valves, or valves that are equipped for rapid local operation with a motorized actuator, in the absence of the final rule.

Interstate transportation of natural gas is subject to economic regulation by FERC. New interstate gas transmission pipelines, and significant changes to existing pipelines, are therefore subject to FERC review and environmental analysis requirements under the National Environmental Policy Act (42 U.S.C. 4321-4347). FEISes that were published or approved after the Pipeline Safety Act of 2011 was enacted have included commitments described below to use ASVs or RCVs on new or upgraded gas transmission pipelines subject to FERC approval. Most operators committed to equipping all mainline valves for remote operation (Table 4-8). The wide use of automated or remotely operated valves demonstrates the feasibility and prevalence of the use of powered actuators or RCVs.

Table 4-8. Gas Transmission Final Environmental Impact Statements Since 2011

Project	Description
Midship Pipeline Company, LLC – Midcontinent Supply Header Interstate Pipeline Project (FERC, 2018)	Citing the 2011 Act, the FEIS states: "As required, Midship Pipeline would use remote control shut-off valves on the proposed pipeline." Midship Pipeline would incorporate the project into gas monitoring and control systems, and the proposed pipeline system would be equipped with remote control valves.
Rover Pipeline (FERC, 2016)	The 78 mainline block valves will be equipped for remote operation from the control center.
Southeast Market Pipelines Project (FERC, 2015a)	All 63 mainline block valves planned for the three proposed projects will be equipped for remote or automatic control.
Algonquin Incremental Market Project (FERC, 2015b)	The project facilities would also be equipped with remote control shutoff valves.
Constitution Pipeline and Wright Interconnect (FERC, 2014a)	The 11 planned valves will be equipped for remote control from a control center.
Sierrita Pipeline Project (FERC, 2014b)	All 6 mainline block valves will be equipped for remote control from a control center.
New Jersey, New York Project (Texas Eastern and Algonquin) (FERC, 2012)	The operator committed to installing remote valves along certain portions of the pipeline.
MLV = mainline valve	

Recent high-profile hazardous liquid pipeline construction projects also use RCVs. The FEIS for TransCanada's Keystone XL Pipeline project indicated that 71 out of 112 intermediate mainline valves along the route would be remotely operated block valves, while an additional 24 would be equipped as check valves.[33] The North Dakota Public Service Commission reported that the Dakota Access Pipeline design includes remote actuators on all mainline valves in the State.[34]

[33] PHMSA believes plans for the Keystone XL pipeline are valid as part of the data assessing current practices, although this project was not completed.

[34] North Dakota Public Service Commission, "PSC Approves Siting Permit for Dakota Access Pipeline Project" http://www.psc.nd.gov/public/newsroom/2016/1-20-16DakotaAccessApproval.pdf (2016).

PHMSA estimates the baseline technology mix assumptions for this analysis using an additional sample of 30 recent gas transmission and hazardous liquid pipeline projects, which is based upon PHMSA inspections and review of operator construction drawings and piping and instrumentation diagrams. PHMSA assumes this information reflects recent practice for the similar types of pipelines regulated by the final rule.[35] (see Table 4-9).

Table 4-9. Summary of Valve Technologies for Gas and Hazardous Liquid Pipeline Projects

Type	In Service	Miles	Valves	RCV	ASV	EFRD	MOV
GT	2019	18.17	12	12	0	0	0
GT	2018	193	11	11	0	0	0
GT	Canceled	600	42	42	0	0	0
GT	Ongoing	303	36	36	0	0	0
GT	Ongoing	60	11	2	0	0	9
GT	2018	835	74	74	0	0	0
GT	2018	159.6	8	0	8	0	0
GT	2018	30	5	0	5	0	0
GT	2019	164	10	0	10	0	0
HL	2018	360	79	15	0	36	28
HL	Ongoing	300	62	11	0	26	25
HL	2018	54	15	15	0	0	0
HL	2019	TBD	TBD	TBD	TBD	TBD	TBD
HL	Ongoing	95	25	19	6	0	0
HL	Ongoing	881	54	54	0	0	0
HL	2020	362	31	31	0	0	0
HL	2020	190	58	26	12	0	20
HL	2019	860	172	82	38	0	52
HL	2020	70	24	20	0	0	4
HL	2020	177	35	24	6	0	5
HL	2019	94	18	10	4	0	4
GT	2020	17	10	10	0	0	0
HL	2020	522	87	21	0	0	66
HL	2020	340	56	12	0	0	44
GT	2021	24	1	1	0	0	0
HL	2020	246	31	22	0	1	8
HL	2019	129	21	11	0	0	10
GT	2022	27	12	12	0	0	0
HL	2020	1117	178	105	70	1	2
HL	2020	877	88	66	0	3	19

[35] For example, gathering lines subject to the rule may be operated by the same entities operating transmission lines, and the gathering lines subject to the rule have been made subject to the rule because of their similarity (in terms of design and operating characteristics, and risks to public safety and the environment) as transmission lines, so similar behavior by operators is expected.

PHMSA's analysis of the data shows substantial use of RMVs.[36] Therefore, PHMSA is estimating that there is a baseline compliance rate, in the absence of this final rule, of 96 percent for gas pipelines and 72 percent for hazardous liquids pipelines, based on the total of RCV, ASV, and EFRD valves installed as a percentage of all valves (see Table 4-10). Planned manually operated valves (MOVs) will require upgrading to serve as RMVs. Some MOVs are equipped with a motorized actuator, and some are not equipped with a motorized actuator so that a motorized actuator in addition to remote communication equipment is required for the upgrade.

Based on PHMSA expert opinion, PHMSA assumes that 50 percent of MOVs are equipped with a motorized actuator for gas pipelines. For hazardous liquid pipelines, PHMSA assumes 25 percent are equipped with a motorized actuator. Actuators are less common on hazardous liquid pipelines because power must be provided, whereas gas pipelines can use the pressure of the gas to power the actuators.

Table 4-10. Summary of Baseline Valve Project Data

Facility Type	RCV	ASV	EFRD	MOV
GT	86%	10%	NA	4%
HL	53%	13%	6%	28%

To avoid underestimating the costs of the final rule, a baseline compliance rate of 75 percent is assumed rather than assuming that the 96 percent compliance rate found in the project data will continue for the period of analysis. Thus, based on these expert opinions and the above data, PHMSA assumes the baseline valve technology mix presented in Table 4-11.

Table 4-11. Summary of Baseline Valve Technology Mix

Facility Type	RCV/ASV/ERFD	Actuated	Manual, Non-Actuated
GT	75%	12.5%	12.5%
HL	72%	7%	21%

[36] PHMSA notes that Type A gas and hazardous liquid gathering operators subject to the final rule may incorporate RMVs less frequently in their new/replacement pipelines, which could in turn increase compliance costs for those lines. However, as noted in Table 4-3, no more than 300 miles of new and entirely replaced gas and hazardous liquid gathering lines would be subject to the RMV installation and operation requirements in this final rule each year—about 5 percent of the total gas and hazardous liquid line mileage. If PHMSA were to assume that none of those Type A gas and hazardous liquid gathering lines would have RMVs in the baseline, the cost of this rulemaking would increase by $0.9 million per year (representing the costs associated with an additional 3.5 RMVs on Type A gas gathering lines and 9.2 RMVs on hazardous liquid lines). However, PHMSA notes that to the extent Type A gas gathering and hazardous liquid line operators exhibit lower baseline compliance levels, the benefits of the rulemaking would be higher.

5. ANALYSIS OF COSTS

This section describes how PHMSA estimated the incremental costs of the final rule, including equipment and program costs.

As described in this section, the costs compelled by the final rule add marginally to costs incurred by the practices of operators in the absence of the rule. Thus, the costs of the rule are much lower than estimates of the costs of converting all existing valves to RMV compliant technology.[37] The equipment costs will be limited to new construction or replacements of pipeline with a diameter, MAOP, and location covered by the rule. Valves are necessary for pipeline operation, so rather than the rule compelling valve installation the rule sometimes requires marginally more expensive valves to be installed than would otherwise be installed. Because current industry practice is to install valves that often are compliant with the rule requirements, the rule adds upgraded equipment costs only for those valves that would otherwise not be compliant with the rule.

5.1. APPLICABLE MILEAGE

5.1.1. Gas Pipelines

The final rule will require ASVs, RCVs, or alternative equivalent technology on new and fully replaced pipelines greater than six inches in diameter, and closure of these valves as soon as practicable but within 30 minutes in the event of rupture identification (or, for hazardous liquid pipelines, within the shutoff time for worst-case discharge). These requirements apply to entirely replaced segments of hazardous liquid pipeline in HCAs that are greater than 6 inches in diameter, and for gas pipelines in any Class location that are greater than 6 inches. The final rule only applies to gas pipelines in Class 1 or Class 2 locations that have a PIR greater than 150 feet.

As shown in Table 5-1, operators install an average of 3,123 miles of gas pipelines annually, of which approximately 93 percent may be greater than or equal to 6 inches in diameter based on the current distribution of gas pipelines by size. Therefore, PHMSA estimated that 2,895 miles of gas pipeline greater than or equal to 6 inches in diameter are installed each year, on average.

Table 5-1. New Construction Mileage (Annual)

Diameter	Miles (Fraction)
All[1]	3,123 (100%)
≥ 6” diameter[2]	2,895 (93%)
1. See Table 4-2.	

[37] In a comment submitted for the PRIA (https://www.regulations.gov/comment/PHMSA-2013-0255-0020), GPA Midstream referenced the ASV and RCV installation cost estimates cited in a Department of Transportation report (Safety Review Task Force, Report on the Research and Special Programs Administration’s Pipeline Safety Program, January 1989), predicting costs of $610 million for installation of ASVs and $680 million for installation of RCVs. These installation costs represent the cost of retrofitting valves throughout the *entire* natural gas pipeline system, which is a much larger undertaking than requiring only valves in new or entirely replace pipeline on a going forward basis, as contemplated by this rulemaking. Further, those estimated costs were noted by the report to have been provided by industry, but details of the assumptions used in the calculation are not available. Further, PHMSA notes that this final rule contemplates that operators can request exemptions from certain of its requirements (regarding installation, spacing, and compliance timelines) for a number of reasons, to include prohibitive costs.

2. Calculated by multiplying all mileage by the percentage greater than 6 inches in diameter based on the 2019 Annual Report, Part H.

Next, PHMSA narrowed this set of potentially affected mileage to exclude Class 1 and Class 2, segments with a PIR less than or equal to 150 ft. The PIR is a calculation from the nominal diameter and the maximum allowable operating pressure (MAOP), as illustrated in Exhibit 5-1 below.[38] PHMSA's data do not include the quantity of mileage by PIR, but in general this exception will exclude a substantial quantity of small diameter pipeline. Thus, PHMSA used an estimate of pipeline greater than 12.75 inches as a proxy for the pipeline mileage over the PIR threshold, based on expert opinion. PHMSA therefore includes a quantity of miles based on pipelines with diameters of 14 inches and greater as reported in the PHMSA 2020 Annual Report, for Class 1 and Class 2. This proxy approach understates the quantity of some miles that have a PIR greater than 150 feet by excluding some relatively high-pressure, small diameter lines; but it also overstates the quantity of miles by including some low-pressure, higher-diameter lines that have a PIR less than 150 feet. Overall, PHMSA views the 14-inch and greater diameter cutoff as a reasonable proxy for the exception for segments with a PIR less than 150 feet in Class 1 and Class 2.

[38] $PIR=0.69\times(MAOP\times d^2)^{0.5}$, where d is the nominal pipe diameter.

Exhibit 5-1. Natural Gas Pipeline PIR, rounded up to the nearest foot and with PIR diameter/pressure combinations below the 150-foot threshold shaded

Maximum Allowable Operating Pressure (PSI)	Nominal Pipe Diameter (Inches)												
	4	6	8	10	12	14	16	18	20	22	24	30	36
50	20	30	40	49	59	69	79	88	98	108	118	147	176
100	28	42	56	69	83	97	111	125	138	152	166	207	249
150	34	51	68	85	102	119	136	153	170	186	203	254	305
200	40	59	79	98	118	137	157	176	196	215	235	293	352
250	44	66	88	110	131	153	175	197	219	241	262	328	393
300	48	72	96	120	144	168	192	216	240	263	287	359	431
350	52	78	104	130	155	181	207	233	259	284	310	388	465
400	56	83	111	138	166	194	221	249	276	304	332	414	497
450	59	88	118	147	176	205	235	264	293	323	352	440	527
500	62	93	124	155	186	217	247	278	309	340	371	463	556
550	65	98	130	162	195	227	259	292	324	357	389	486	583
600	68	102	136	170	203	237	271	305	339	372	406	508	609
650	71	106	141	176	212	247	282	317	352	388	423	528	634
700	74	110	147	183	220	256	293	329	366	402	439	548	658
720	75	112	149	186	223	260	297	334	371	408	445	556	667
750	76	114	152	189	227	265	303	341	378	416	454	567	681
800	79	118	157	196	235	274	313	352	391	430	469	586	703
850	81	121	161	202	242	282	322	363	403	443	483	604	725
900	83	125	166	207	249	290	332	373	414	456	497	621	746
950	86	128	171	213	256	298	341	383	426	468	511	639	766
1000	88	131	175	219	262	306	350	393	437	481	524	655	786
1050	90	135	179	224	269	314	358	403	448	492	537	671	805
1100	92	138	184	229	275	321	367	412	458	504	550	687	824
1150	94	141	188	234	281	328	375	422	468	515	562	702	843
1200	96	144	192	240	287	335	383	431	479	526	574	718	861
1250	98	147	196	244	293	342	391	440	488	537	586	732	879
1300	100	150	200	249	299	349	399	448	498	548	598	747	896
1350	102	153	203	254	305	355	406	457	508	558	609	761	913
1400	104	155	207	259	310	362	414	465	517	568	620	775	930

PHMSA assumed that the new installations are located across class and HCAs in the same proportion as existing pipelines. PHMSA then multiplied the expected new and replaced mileage by the percent of gas pipelines greater than 12.75 inches in diameter (63.0%) in the case of Class 1 and Class 2, and 6 inches (92.7%) for Class 3 and Class 4, to estimate the mileage potentially subject to the final rule.[39] Table 5-2 shows the resulting estimates of mileage by location. PHMSA assumed that the pipeline mileage installed by decade reported by operators in their annual reports is inclusive of replacements of two miles or more in length. By tailoring the final rule based on pipeline diameter and PIR, and exempting Type B and Type C gas gathering lines, PHMSA expects that the gas pipeline mileage affected each year will be reduced from 3,123 miles to 2,072 miles.

[39] These percentages were calculated using PHMSA 2020 Annual Report data.

Table 5-2. Estimated Annual Gas Mileage Subject to Final Rule		
Location	**Percent in Class Location of All Existing Pipeline Mileage[1]**	**Affected New Mileage**
Class 1 PIR > 150 ft	78.6%	1,546
Class 2 PIR > 150 ft	10.0%	197
Class 3	11.1%	322
Class 4	0.3%	8
Total	100.0%	2,072

Note: Detail may not add to total due to rounding
1. Source: PHMSA 2020 Annual Report.

To estimate the number of valves associated with new and replaced mileage, PHMSA assumed the maximum allowed valve spacing (per 49 CFR 192.179). Table 5-3 shows the resulting estimates.

Table 5-3. Estimation of Number of Valves, Gas Pipelines			
Class	**Affected Miles**	**Max Valve Spacing[1]**	**RMVs per Year**
1 (>150 ft PIR)	1,546	20	77
2 (>150 ft PIR)	197	15	13
3	322	8	40
4	8	5	2
Total	**2,072**	**NA**	**132**

Note: Detail may not add to total due to rounding.
NA = not applicable
1. See 49 CFR 192.179

5.1.2. Hazardous Liquid Pipelines

As shown in Table 5-4, operators install an average of 2,373 miles of onshore hazardous liquid pipeline annually. Almost all (97 percent) of hazardous liquid pipeline mileage is greater than or equal to 6 inches in diameter. Therefore, PHMSA estimated that approximately 2,295 miles of hazardous liquid pipelines greater than or equal to 6 inches in diameter are newly constructed or replaced each year. PHMSA assumed that the pipeline mileage installed by decade reported by operators in their annual reports is inclusive of replacements of 2 miles or more in length.

Table 5-4. Annual New and Replaced Hazardous Liquid Mileage	
Component	**Miles (Fraction)**
Pipelines installed annually[1]	2,373 (100%)
Pipelines installed annually ≥ 6” diameter[2]	2,295 (97%)

1. See Table 4.2.
2. Calculated by multiplying total annual installed mileage by the percentage of pipelines greater than 6 inches in diameter based on the 2019 Hazardous Liquid Annual Report (2,373 miles × 0.9671 = 2,295 miles).

The final rule requires maximum distances between rupture-mitigation valves of 20 miles for hazardous liquid pipelines, 15 miles if in HCA locations and 7.5 miles for HVL pipelines and requires monitoring equipment for all RMVs. PHMSA assumes an average valve spacing of 15 miles to comply with the final rule. Table 5-5 provides the assumptions and estimation of 153 valves per year on new and replaced hazardous liquid pipelines.

Table 5-5. Estimation of Number of Valves, Hazardous Liquid Pipelines

Total Miles	Spacing between Valves (Miles)	Total Number of Valves
2,295	15	153

5.2. COMPLIANCE TECHNOLOGIES

To estimate the potential installation of incremental compliance technologies, PHMSA estimated the baseline scenario and the mode of operation under the final rule. RMVs under the baseline scenario will comply with the final rule (no incremental compliance technologies will be needed for compliance). For other technology, including locally operated valves in the baseline scenario, PHMSA estimated that operators will need to install communications equipment, and in some cases actuators, under the final rule.

5.2.1. Estimation of Equipment Needs for Gas Pipelines

In a 2015 survey by the Interstate Natural Gas Association of America (INGAA), operators who reported to the number of ASVs and RCVs indicated that 41 percent of valves are currently automated.[40] However, operators may be more likely to equip new pipelines with ASVs, RCVs, or actuated valves (i.e., less use of manual valves on new pipelines). The GAO reported in 2013 that INGAA had committed in a separate report to a 1-hour response time, and reported the installation of 1,800 automatic and RCVs, for large-diameter, new and existing pipelines in highly populated areas.

As described in Section 4.4, Table 4-11, the forward-looking PHMSA estimate for new construction is that 75 percent of valves will be equipped with technology compliant with the final rule, in the absence of the final rule. Table 5-6 shows that the baseline specifications result in an estimated 15 actuated valves installed annually that will need communications equipment upgrades, and 15 valves installed annually that will need an actuator installation in addition to communications equipment upgrades.

Table 5-6. Estimation of Incremental Equipment Upgrades Needed Annually, Gas Pipelines[1]

Type of Valve	Baseline Estimated Percentage	Baseline Estimated Number[2]
RCV	75%	99
Actuated, not remote controlled	12.5%	17
Manual, not actuated	12.5%	17

[40] Interstate Natural Gas Association of America (INGAA). 2015 Member Survey on Valves and Automation. Personal communication with C.J. Osman, Director of Operations, Safety and Integrity, September 20, 2016.

Table 5-6. Estimation of Incremental Equipment Upgrades Needed Annually, Gas Pipelines[1]		
Type of Valve	**Baseline Estimated Percentage**	**Baseline Estimated Number[2]**
Total	100%	132

Note: Detail may not add to total due to rounding.
RCV = remote control valve
1. Valves that are not RCVs in the baseline will need actuator upgrades and/or communications equipment upgrades.
2. Calculated as total number of valves multiplied by estimated percentage.

5.2.2. Estimation of Equipment Needs for Hazardous Liquid Pipelines

As described in Section 4.4, Table 4-11, PHMSA estimates that 72 percent of hazardous liquid valves will be equipped with technology compliant with the final rule, in the absence of the final rule. Of the remainder, 7 percent of valves are estimated to be actuated, and 21 percent are non-actuated. Based on these assumptions, 43 valves will require modification, annual, including 11 actuated and 32 non-actuated (Table 5-7).

Table 5-7. Estimated Baseline Mode of Operation, Hazardous Liquid Pipeline Valves

Type of Valve	Baseline Estimated Percentage	Baseline Estimated Number[2]
RCV	72%	111
Actuated	7%	11
Manual, not actuated	21%	32
Total	100%	153

Note: Detail may not add to total due to rounding.
RCV = remote control valve
1. Valves that are not RCVs in the baseline will need actuator upgrades and/or communications equipment upgrades.
2. Calculated as total number of valves multiplied by estimated percentage

5.2.3. Unit Costs

Table 5-8 presents the incremental cost of equipping existing actuated and non-actuated valves to operate as an RMV. An actuated valve is already motorized or has some other equivalent means of mechanized operation. The upgrade cost is therefore the incremental cost of communications equipment and other systems required to enable remote operation of the actuator. Communications equipment is needed to operate the actuator remotely from a control center. Additionally, each valve site likely needs a remote terminal unit to control the actuator, backup power supplies, and possibly an above-ground or underground structure to house the additional equipment (building in Table 5-8). Finally, the operator will need to equip the covered pipeline segments with pressure monitoring equipment, if it is not already equipped, to detect ruptures.

Some new and replaced valves may already have some of these components installed, and therefore costs may be slightly overstated. Specifically, PHMSA expects that most valve sites will not require new structures to house the control equipment. If the valve is not actuated, then in addition to the above costs, the operator will need to purchase and install an actuator. These upgrade costs are substantially lower than the full cost of installing an RMV in new construction because they reflect only the marginal cost above the cost of installing a previously planned valve that is not an RMV in the construction process.

Table 5-8. Unit Cost to Equip Actuated Valve for Remote Operation (2020$)

Diameter Range (Inches)	Manual to RMV:	Annualized Cost, Manual (7%)	Automating Actuator to RMV	Annualized Cost, Automating (7%)
Gas				
6.625-12.75	$84,000	$7,208	$56,000	$4,805
16-24	$102,000	$8,753	$56,000	$4,805
30-36	$119,000	$10,211	$56,000	$4,805
Average Unit Cost[3]	*$101,424*	*$8,703*	*$56,000*	*$4,805*
Additional Monitoring Equipment	*$2,500*	*$299*	*$2,500*	*$299*
Total Unit Cost	**$103,924**	**$9,002**	**$58,500**	**$5,105**
Hazardous Liquid				
6.625-12.75	$104,000	$8,924	$56,000	$4,805
16-24	$122,000	$10,469	$56,000	$4,805
30-36	$139,000	$11,928	$56,000	$4,805
Average Unit Cost[3]	*$110,508*	*$9,483*	*$56,000*	*$4,805*
Additional Monitoring Equipment	*$2,500*	*$299*	*$2,500*	*$299*
Total Unit Cost	**$113,008**	**$9,782**	**$58,500**	**$5,105**

1. The estimated cost for pressure monitoring equipment is PHMSA best professional judgement. All other estimates for unit cost are derived from information provided by a vendor.
2. Annualized over useful life of 25 years for the remoted upgrade and 13 years for the additional monitoring equipment, using a 7 percent discount rate. Calculated using the Microsoft Excel PMT function, which returns the payment amount for every period (year) on an amount using constant payments and a constant interest rate.
3. Weighted by the percentages of total pipeline in each diameter category. Excludes additional monitoring equipment.

5.2.4. Total Equipment Costs

Based on the estimated number of equipment upgrades needed and unit costs, Table 5-9 presents the total costs for both gas pipelines and hazardous liquid pipelines.

Table 5-9. Total Annualized Cost for Valve Equipment Upgrades for Remote Operation (2020$)

System Type	Number of Upgrades	Total Annualized Cost (Millions)
Gas pipelines	33	$1.9
Hazardous liquid pipelines	43	$3.0
Total	73	$5.0

Note: Detail may not add to total due to rounding.

5.3. PROGRAM CHANGES

PHMSA assumed that the final rule will require an incremental level of effort from all operators to incorporate rupture identification, emergency planning, 9-1-1 notification, and failure investigation procedures. This assumption may overstate costs and benefits considering actions already taken by State regulators and industry associations regarding emergency response procedures and valve technologies. For example, the GAO's 2013 report cites National Association of Pipeline Safety Representatives statements that several States have established response time standards for pipeline leaks, while INGAA members have committed to a 1-hour response time for large-diameter natural gas pipelines in populated areas. The current PSR already require leak detection on hazardous liquid pipelines (§ 195.452(i)(3)) and investigation of failures on both gas transmission and hazardous liquid pipelines (§§ 192.617 and 195.402(c)(5)).

Each operator should already have procedures in place for the basic valve operability inspections in accordance with existing requirements in 49 CFR parts 192 and 195. Validation drills under the final rule only apply for locally closed valves; the incremental compliance technology costs discussed in Section 5.2 reflect use of RMVs only. The final rule will require operators to develop and implement lessons learned from post-incident reviews, assess the effectiveness of their rupture-mitigation performance when a rupture occurs or whenever any event involves the closure of RMVs or alternative equivalent technology, and take corrective actions. The final revisions to § 192.617 expand failure investigation requirements to add specificity regarding post-accident procedures, identifying and implementing lessons learned and creates additional requirements for investigating closures and ruptures. The final revisions to § 195.402 apply similar requirements to hazardous liquid pipelines.

Other requirements codify recommended safety procedures. In 2012, PHMSA published an advisory bulletin,[41] reminding operators to immediately contact and establish communication with public safety access points that serve the communities and jurisdictions where their pipelines are located when there are indications of a pipeline facility emergency. Section 192.615(a) already contains the following requirement for emergency operations:

> "…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…notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency…."

Given these considerations, PHMSA estimated a one-time incremental impact of 40 hours per operator to develop new rupture identification and response procedures. The cost estimates for these hours are based on labor rates for engineers in the pipeline transportation industry (Table 5-10). PHMSA annualized incremental procedural costs over 20 years. Table 5-11 shows the result.

[41] 77 FR 61826 (Oct. 11, 2012).

Table 5-3. Estimated Labor Costs for Petroleum Engineers[1] (2020$)		
Industry	**Mean Hourly Wage**	**Total Hourly Labor Cost[2]**
Pipeline transportation of natural gas	$60.61	$87.84
Pipeline transportation of crude oil	$66.80	$96.81
Source: Bureau of Labor Statistics (BLS) (2021a; b) 1. BLS Standard Occupational Classification 172171. 2. Mean hourly wage divided by 0.690 to account for benefits based on the Employer Cost of Employee Compensation (wages account for 69.0 percent of total compensation for all civilian employees; e.g., for natural gas: $60.61 wage / 0.690 = $87.84 labor rate including benefits).		

Table 5-4. Estimated Procedure Development Costs (2020$)				
System Type	**Number of Operators (OPIDs)**	**Incremental Hours per Operator**	**Total Cost (Millions)[2]**	**Annualized Cost (Millions)[3]**
Gas pipelines	1,304	40	$4.6	$0.4
Hazardous liquid pipelines	508	40	$2.0	$0.2
Total	1,812	40	$6.5	$0.6
Note: Detail may not add to total due to rounding. 1. Represents effort to revise emergency response, failure investigation, and valve risk analysis plans (see Table 3-1). 2. Number of operators multiplied by the hours per operator multiplied by the appropriate labor rate in Table 5-10 (e.g., for gas transmission: 1,304 × 40 × $87.84 = $4.6 million). 3. Annualized over 20 years using a 7 percent discount rate (e.g., for gas transmission: = - PMT (0.07,20,4.6 million); see Table 5-9 for PMT function).				

PHMSA assumed that the changes to rupture identification and response procedures will require a small incremental change to annual operations training requirements. Operations personnel must already have annual operations training. PHMSA estimated that the more prescriptive response requirements and new rupture identification requirements could add 30 minutes to this training per employee per year. PHMSA identified three occupations defined by the Department of Labor that are likely to be involved in pipeline system operations: Gas Plant Operators; Petroleum Pump System Operators, Refinery Operators, and Gaugers; and Pumping Station Operators. Table 5-12 shows the number of employees in these categories and Table 5-13 shows their median wages.

Table 5-5. Pipeline Operations Employment				
Occupation	**Pipeline Transportation of Natural Gas**	**Pipeline Transportation of Crude Oil**	**Other Pipeline Transportation**	**Total**
Gas plant operators	5,220	180	80	5,480
Petroleum pump system operators	2,160	2,380	2,730	7,270
Pumping station operators	1,960	110	200	2,270
Total	9,340	2,670	3,010	15,020

Table 5-5. Pipeline Operations Employment				
Occupation	Pipeline Transportation of Natural Gas	Pipeline Transportation of Crude Oil	Other Pipeline Transportation	Total
Source: Bureau of Labor Statistics (2021a); Standard Occupation Codes 51-8092, 51-8093, and 53-7070.				

Table 5-6. Pipeline Operations Labor Costs Per Hour (2020$)[1]			
Occupation	Pipeline Transportation of Natural Gas	Pipeline Transportation of Crude Oil	Other Pipeline Transportation
Gas plant operators	$50.54	$51.86	$51.52
Petroleum pump system operators	$53.67	$55.32	$51.07
Pumping station operators	$48.04	$49.71	$44.28
Source: Bureau of Labor Statistics (2021a); Standard Occupation Codes 51-8092, 51-8093, and 53-7070. 1. Mean hourly wage divided by 0.690 to account for benefits based on the Employer Cost of Employee Compensation (wages account for 69.0 percent of total compensation for all civilian employees)			

Table 5-14 shows the estimated costs assuming half of the employment in the "other pipeline transportation" category represents hazardous liquid pipeline operators. PHMSA makes this assumption because the category other pipeline transportation includes pipelines not regulated by PHMSA (e.g., coal, slurry, and chemicals other than petroleum products), and therefore employees not subject to the final rule.

Table 5-7. Estimated Incremental Annual Training Costs (Millions 2020$)[1]		
Occupation	Gas[1]	Hazardous Liquid[2]
Gas plant operators	$0.13	$0.01
Petroleum pump system operators	$0.06	$0.10
Pumping station operators	$0.05	$0.00
Total	$0.24	$0.11
Note: Detail may not add to total due to rounding. 1. Calculated as employment in pipeline transportation of natural gas (Table 5-12) multiplied by median wage (Table 5-13) and 0.5 hour (e.g., for gas plant operators: 5,220 employees × $50.54 per hour × 0.5 hour = $0.13 million). 2. Calculated as employment in the category pipeline transportation of crude oil plus half of employment in the category other pipeline transportation (Table 5-12) multiplied by respective median wage (Table 5-13) and 0.5 hour [e.g., for gas plant operators: (180 employees in crude oil category × $51.86 per hour × 0.5 hour) + ((80 employees in other pipeline transportation category × 0.5) × $51.52 per hour × 0.5 hour) = $0.01 million].		

In addition to developing and implementing new rupture identification and response programs, operators will have to comply with more specific instructions for analyzing post-incident lessons learned and new requirements for detailed analysis of rupture and valve-shutoff events (§§ 192.617 and 195.402(c)(5)). PHMSA incident reports identify rupture events. Given that current PSR already require investigation of failures, PHMSA estimated an incremental post-incident analysis impact to pipeline engineers of 40 hours per rupture. Table 5-15 summarizes the resulting cost estimates for both system types.

Table 5-8. Incremental Post-Rupture Analysis Costs (2020$)

System Type	Ruptures per Year[1]	Incremental Hours per Incident[2]	Annual Cost (Millions)[3]
Gas transmission	26	40	$0.1
Hazardous liquid	22	40	$0.1
Total	47.2	NA	$0.2

Note: Detail may not add to total due to rounding.
NA = not applicable
1. Source: PHMSA incidents reports from 2010-2020.
2. Source: PHMSA best professional judgement (considering existing requirements to investigate failures).
3. Calculated as ruptures per year multiplied by hours per incident and hourly labor cost from Table 5-10 (e.g., for gas transmission: 26 ruptures × 40 hours × $87.84 per hour = $0.1 million).

Table 5-16 provides a summary of the estimated program costs.

Table 5-9. Summary of Annual Costs for Program Changes (Millions 2020$)

System Type	Procedure Development	Training	Post-Incident Analysis	Total Annual Cost
Gas transmission	$0.43	$0.24	$0.09	**$0.76**
Hazardous liquid	$0.19	$0.11	$0.09	**$0.38**
Total	$0.62	$0.35	$0.17	**$1.14**

Note: Detail may not add to total due to rounding.
Source: Table 5-11 (Procedure Development), Table 5-14 (Training), and Table 5-15 (Post-Incident Analysis).

5.4. POTENTIAL UNQUANTIFIED COSTS

The rule may result in some unquantified costs associated with automatic valve closures that could occur due to false indicia of a rupture. As noted above, PHMSA expects that operators will install RCVs at a greater rate than ASVs, but to the extent that the rule leads to greater adoption of ASVs operators will need to apply programming logic that will lead to valve closures upon occurrence of rupture indicia without human intervention. Pipeline operators are free to set any pressure reduction thresholds appropriately for the ASVs that they install, and PHMSA expects that operators will not set thresholds that are likely to lead to unnecessary or harmful valve closures. However, such occurrences are possible, and PHMSA has not quantified the costs to pipeline operators or gas users of disruptions to gas service, or any other damages that could occur.

5.5. SUMMARY OF COSTS

Table 5-17 summarizes the total compliance costs including equipment and programmatic costs.

Table 5-10. Summary of Annualized Costs of Final Rule[1] (Millions 2020$)

System Type	Equipment Upgrades	Program Changes	Total
Gas transmission	$1.9	$0.8	**$2.7**

Table 5-10. Summary of Annualized Costs of Final Rule[1] (Millions 2020$)			
System Type	**Equipment Upgrades**	**Program Changes**	**Total**
Hazardous liquid	$3.0	$0.4	**$3.4**
Total	$5.0	$1.1	**$6.1**
Note: Detail may not add to total due to rounding. 1. Reflects 7 percent discount rate.			

As noted in Section 4.4, designs of new and replaced pipelines already incorporate ASV and RCV technology. This trend may increase in the future in the absence of the final rule, in which case the baseline assumptions based on current practice may serve to overstate the incremental impact. Nonetheless, compared to new construction costs, the incremental costs of the final requirements are small. IHS Economics (2016) estimated crude oil pipeline construction costs (excluding right-of-way acquisition) of $1,551,000 per mile for 12-inch-diameter pipelines and $1,867,000 for 20-inch-diameter pipelines using software that it developed for analyzing the costs of new oil and gas projects.[42] In comparison, incremental unit equipment upgrade costs of $58,500 for actuated valves and $104,000 - $113,000 for non-actuated valves are only approximately $1,900 per mile (Table 5-8).[43] Thus, the incremental costs may represent less than half a percent of per-mile construction costs.[44] Low compliance costs contribute to PHMSA's determination that the rule is justified for hazardous liquid pipelines above 6 inches in diameter, and for gas transmission pipelines and Type A gas gathering pipelines above 6 inches in diameter (and where PIR is above 150 in a Class 1 or Class 2 location).

The low compliance cost estimates are further supported by the flexibilities provided in the final rule. Operators can (subject to PHMSA's review) make a site-specific case before installation of an alternative equivalent technology that the technology would provide an equivalent level of safety to an RMV, and, if that proposed alternative equivalent technology is a manual valve, installation of an RMV would be economically, technically, or operationally infeasible. Further, PHMSA is providing procedural mechanisms allowing operators to request extensions of compliance timelines for installation of RMVs and alternative equivalent technology if such timelines are economically, technically, or operationally infeasible for near-term construction and replacement projects.

[42] IHS Economics, "The Economic Impact of Crude Oil Pipeline Construction and Operation" at 5 (2017), http://www.nam.org/Issues/Energy-and-Environment/Crude-Oil-Pipeline-Impact-Study.pdf.
[43] The calculation is: (($58,500 per valve × 11 hazardous liquid valves) + ($113,008 per valve × 32 hazardous liquid valves)) ÷ 2,295 hazardous liquid pipeline miles = $1,856 per mile.
[44] The calculation is: $1,856 incremental cost per mile ÷ $1,551,000 construction cost per mile = 0.1 percent.

6. ANALYSIS OF BENEFITS

PHMSA expects that this final rule will increase public safety and help to protect the environment. While the potential consequences of a gas pipeline rupture differ from that of a hazardous liquid pipeline rupture, society benefits from faster isolation of ruptured pipeline segments because faster isolation can reduce the potential damages—to people, property, and the environment—from such incidents. Because a detailed projection of avoided incidents and avoided costs of those incidents is not available, PHMSA is not able to quantify the benefits, so this section qualitatively discusses the potential benefits of the final regulatory revisions.

PHMSA notes that there are differences in the effects between gas and hazardous liquids incidents that are likely to affect the benefits of this final rule for different types of pipelines. The damages of hazardous liquid pipeline incidents are dominated by cleanup costs. The marginal benefit of a more rapid response time could primarily be measured by the amount of hazardous liquid to clean up. Therefore, it could be possible estimate the benefit of this rule for hazardous pipelines in terms of reduction in spills after a hazardous liquid pipeline incident. In contrast, natural gas pipeline incidents result predominately in fatalities, injuries or property damages that are not linearly related to the quantity of natural gas released. For small incidents and those in remote locations, damages may be limited to pipeline repair costs; larger incidents are more likely to result in ignition and extensive property damage and injury, particularly in highly developed areas or locations with high population density. Reduction in cumulative gas release over these diverse incidents would not imply avoided damages in the simple rule of thumb way that hazardous liquid releases do—but such reductions in greenhouse gas emissions, would similarly have a per-unit-emitted benefit to the environment and in turn to society. Some quantitative estimates are expressed below.

6.1. GAS PIPELINES

This section discusses the benefits of quicker gas pipeline shutdown, including reduced fire damages and greenhouse gas emissions. Due to uncertainties the total value of the emission reductions described in this section are not quantified.

6.1.1. Reduced Fire Damages

The most significant benefit of quicker gas pipeline shutdown is the added safety that comes from reduced fire risk. PHMSA estimates 30 percent of gas pipeline ruptures are ignited; however, the time to ignition is not collected in required PHMSA incident reports. The sparking of rupturing material or fill moved by gas pressure can be the source of immediate ignition, or the released vapor cloud might not ignite until it expands to an ignition source farther away or later in time. Cutting off the gas reduces the chance of igniting a fire and explosion; furthermore, it speeds up the firefighting and rescue operations if the gas does ignite. Together, these factors reduce the likelihood and consequences of post-incident fires.

Research commissioned by PHMSA (ORNL 2012) demonstrates significant benefits from faster firefighting response in the immediate vicinity of major incidents. ORNL 2012 estimated damages from gas ruptures by modeling the exposure of buildings and personal property to heat over the duration of a pipeline-rupture-fueled fire. ORNL 2012 found that benefits accrue from shutting down gas pipelines more rapidly over the baseline scenario because of shorter heat exposure time and earlier firefighting efforts.

According to the ORNL 2012 study, "the technical, operational, and economic feasibility and potential cost benefits of installing ASVs and RCVs in newly constructed or fully replaced pipelines need to be evaluated on a case-by-case basis." While the final rule will remove some flexibility from operators, the requirements will apply only to Class 4 sites and sites operated at higher pressure and with pipeline diameters such that the 150-foot PIR threshold is exceeded. Also, the final rule provides flexibility in equipment and methods used to meet the requirements, so site-specific differences can be accommodated.

ORNL 2012 indicates that, for gas pipelines, much greater benefits will be gained when closure times are closer-in-time to the initiation of the rupture. When ASV and RCV equipment is installed and operated either immediately upon, or close-in-time to, notification of potential rupture, the valves can typically be closed much more quickly than the 30-minute limit in this final rule—for this reason, the final rule requires that the valves must be closed as soon as practicable following rupture identification. The value of the commodity lost and emission damages will be reduced after 30 minutes, but potential property damages are likely to be largely complete before the 30-minute limit. The final rule is expected to often shorten closure times to substantially less than the minimal requirement, thus providing substantial value in avoided property damage. While the final rule allows a response time of up to 30 minutes if circumstances warrant it, shorter times than the minimal requirements are expected after the equipment is installed and operational. Table 6-1 provides a summary of the ORNL (2012) estimates.

Table 6-1. Avoided Damage Costs for Hypothetical Natural Gas Pipeline Releases Resulting from Firefighting Activities Within 1.5 Times PIR Location[1] (Millions $2020)

Location	12" Diameter, 300 psig MAOP		42" Diameter, 1,480 psig MAOP	
	8 Minutes	13 Minutes	8 Minutes	13 Minutes
Class 1 & 2 HCA				
Buildings or dwellings intended for human occupancy and a PIR greater than 660 ft	NA	NA	$5.195	$2.078
Identified site consisting of buildings with four or more stories	$0.682	$0.341	$5.195	$2.078
Outside recreational facility	$0.912	$0.507	$2.028	$0.811
Class 3 HCA				
Buildings or dwellings intended for human occupancy	$2.337	$1.299	$9.352	$5.195
Outside recreational facility	$0.912	$0.507	$3.557	$0.811
Class 4 HCA				
Buildings or dwellings intended for human occupancy	$1.704	$1.023	$6.818	$4.091

Source: ORNL [2012; Table 5.1 updated to 2020 dollars using the Bureau of Economic Analysis Implicit Price Deflator (gross domestic product; 2012= 100, 2020=113.625].
HCA = high consequence area
MAOP = maximum allowable operating pressure

Table 6-1. Avoided Damage Costs for Hypothetical Natural Gas Pipeline Releases Resulting from Firefighting Activities Within 1.5 Times PIR Location[1] (Millions $2020)				
Location	**12” Diameter, 300 psig MAOP**		**42” Diameter, 1,480 psig MAOP**	
	8 Minutes	**13 Minutes**	**8 Minutes**	**13 Minutes**

NA = not applicable (PIR is less than 660 ft)
PIR = potential impact radius
Psig = pounds per square inch gauge, pressure net of atmospheric pressure
1. Compared to 60-minute baseline response time.

ORNL 2012 did not evaluate potential additional benefits from reduced casualties due to earlier evacuation, firefighting, and rescue operations, or increased public confidence in the safety of new gas pipelines.

6.1.2. Reduced Emissions Benefits

Quick shutdown of gas pipeline ruptures also reduces greenhouse gas emissions. Natural gas is mostly made of methane, a greenhouse gas with a climate change impact 84 times stronger than carbon dioxide over a 20-year period, and 28 times stronger over a 100-year period.[45]

From 2010 to 2020, the average release volume for a rupture was 36,525 MCF (thousand cubic feet) with an average annual total release of 966,265 MCF. These figures may modestly overstate methane emissions because natural gas contains other pollutants such as carbon dioxide and other hydrocarbons. Additionally, if the natural gas release from a rupture ignites, the methane emissions can be substantially lower since the methane is partially converted to carbon dioxide and water vapor through combustion. Although PHMSA has not quantified the value of avoided greenhouse gas emissions, this is a significant benefit of the more rapid rupture isolation required by the final rule.

6.1.3. Summary

The ORNL 2012 analysis and the conclusions of multiple NTSB investigations demonstrate the significant reduction in incident consequences that are possible if gas pipeline ruptures are quickly identified and shut down. Specifically, the simulation in ORNL 2012 shows that rapid gas shutoff can significantly reduce potential incident consequences, especially in Class 3 and 4 locations and on high-diameter pipelines. Faster valve closure reduces the risk of a gas release igniting or exploding and can reduce the amount of fire damage nearby if there is ignition. Cutting off the fuel to a major gas fire allows first responders to begin firefighting and rescue operations earlier with direct benefits to people and property. In Class 3 locations, ORNL 2012 estimated between $2.3 and $9.4 million in reduced fire damage resulting from a rupture, depending on diameter and pressure, if operators reduce the pipeline shutdown time from 60 minutes to 8 minutes. Similarly, if the shutdown time from rupture initiation is decreased from 60 minutes to 13 minutes, the reduction in fire damages ranges between $1.3 and $5.2 million. Finally, rupture mitigation reduces product losses and greenhouse gases released to the atmosphere. In addition to the ORNL simulations, PHMSA considered historical damages of pipeline incidents. In particular, as demonstrated above in Table 4-5, reported damages in Class

[45] EPA, “Understanding Global Warming Potentials,” https://www.epa.gov/ghgemissions/understanding-global-warming-potentials (last visited May 27, 2021).

1 and Class 2 locations averaged over $28 million per year in 2020 dollars from 2002 – 2020. This demonstrates that costly incidents can occur in remote locations. While not included in the historical data presented in Table 4-5, PHMSA also considered the Carlsbad, NM pipeline rupture, which led to 12 fatalities even though it occurred in a rural area.[46]

The benefit categories in this section only reflect areas where PHMSA has some quantitative information to present. Reducing the damage of the most severe pipeline incidents has other benefits that are not as easy to quantify or monetize. For example, ORNL 2012 identifies reduced damages to homes and vehicles but does not estimate potential avoided casualties. Faster emergency response can lead to fewer fatalities and serious injuries. Firefighting at the rupture location cannot begin until the fuel source is cut off, and rescuers cannot begin to save victims while the area is still dangerously hot. Faster emergency response also helps to mitigate damage to nearby infrastructure such as roads, other pipes, power lines, and communication lines.

An example of slow rupture isolation in an incident without RMVs available is the April, 2016 30-inch gas transmission pipeline rupture in Westmoreland County, PA. State officials reported that it took approximately one hour to shut off the source of gas.[47] One man suffered serious burns as he fled the uncontrolled blaze.[48] In addition to the serious injury, the operator estimated damages of approximately $3 million. The fire damaged 800 feet of highway that remained closed weeks after the incident.[49]

In contrast, quick rupture isolation can result in significantly lower damages. As an example, on November 13, 2015, a third-party excavator punctured a 34-inch gas transmission pipeline operating at 660 psig near Bakersfield, CA.[50] The gas ignited, resulting in one fatality and two injuries. The pressure loss was identified within 4 minutes, and the ASVs isolated the punctured section of the pipeline within 14 minutes. At this Class 1 location, approximately 90 gas customers lost service, but the majority of those lost services were restored by the next day. A nearby home and a barn were damaged by the fire, but the potential for additional damage or service outages was prevented by the quick valve closure and a timely first responder access.

6.2. HAZARDOUS LIQUID PIPELINE RUPTURES

Responding faster to hazardous liquid pipeline ruptures can avert catastrophic consequences, such as those from the Enbridge incident. ORNL 2012 estimated the benefits of mitigating

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[46] NTSB, Accident Report NTSB/PAR-03/01, "Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico August 19, 2000" (2003), https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR0301.pdf

[47] Litvak, "Natural Gas Explosion Rocks Westmoreland County and U.S. Gas Markets," Pittsburgh Post-Gazette (May 1, 2016), http://www.post-gazette.com/local/westmoreland/2016/04/29/Emergency-crews-respond-to-gas-well-explosion-in-Westmoreland-County-pennsylvania/stories/201604290161.

[48] Hardway, "'It Was Like Looking into Hell:' Natural Gas Explosion Sparks Large Fire in Salem Township," Pittsburg Channel 4 News (Apr. 30, 2016), http://www.wtae.com/news/reports-gas-well-on-fire-in-salem-township/39279470.

[49] NTSB, Accident Report NTSB/PAR-14/01, "Columbia Gas Transmission Corporation Pipeline Rupture, Sissonville, West Virginia December 11, 2012" (2014), http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1401.pdf.

[50] Incident report number 20150148 information is available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/data_statistics/pipeline/incident_gas_transmission_gathering_jan2010_present.zip

ruptures on hazardous liquid pipelines through modeling a worst-case, guillotine-style break under different scenarios of pipeline diameter, flow rate, pressure, elevation, and ignition. Rapid response to hazardous liquid pipeline ruptures mitigates damages by reducing the volume of product released into the environment.

The ORNL 2012 simulation provided worst-case estimates of total spill volumes and drain-down volumes mirroring the worst-case discharge calculation in 49 CFR 194.105(b)(1) (Table 6-4). Although the modeled spill volumes are higher than have been observed in the incident history, they are consistent with worst-case discharge calculations submitted by operators for similar pipeline characteristics. Thus, damages exceeding historical averages are possible. The low frequency and highly variable consequences of possible future spills is a significant source of uncertainty.

Table 6-2. Estimated Worst-Case Discharges (Barrels)

Diameter	Shutdown Time			
	90 Minutes	60 Minutes	30 Minutes	3 Minutes
8”	2,850	2,290	1,731	1,227
12”	6,413	5,154	3,895	2,762
16”	11,399	9,161	6,923	4,909
24”	25,649	20,613	15,577	11,045
30”	40,077	32,208	24,340	17,258
36”	57,710	46,379	35,049	24,851

Source: ORNL (2012), Tables: A-1; A-37; A-73; A-111; A-145; A-181

This difference between historical and modeled values is reflected in similar studies. A 2007 ENSR analysis of the potential impacts of the proposed Keystone XL Pipeline conducted a similar exercise to determine the expected consequences of a release on the planned project. According to ENSR, “Estimated spill volumes were based on leak rate and time to isolate for throughputs of 435,000 and 591,000 bpd along the Keystone Pipeline system. The study currently assumes drain down within the affected segment” (ENSR Corporation 3-2).[51] The analysts noted that real world spill volumes have been significantly smaller than the calculated maximum drain-down volume. ENSR attributes the difference to over-estimated drain-down volumes and not accounting for depressurizing.

Pipeline age is also an important factor. Available evidence indicates that ruptures are more frequent in new pipelines, presumably due to construction related damage and flaws. Older pipelines exhibit a lower rate, although, very old pipelines built using outdated standards fail at a higher rate, but not as frequently as new construction.[52]

[51] Pipeline Risk Assessment and Environmental Consequence Analysis, ENSR Corporation, March 2007, Document No.: 10623-004. https://puc.sd.gov/commission/dockets/HydrocarbonPipeline/2007/HP07-001/Disk/Exhibit%20C/5March07/RiskAssessment/3riskassessment033007.pdf

[52] See http://pstrust.org/wp-content/uploads/2013/03/Incidents-by-age-of-pipes-PST-spring2015-newsletter-excerpt.pdf.

Even the in the absence of an actual worst-case incident, historical incidents have resulted in large spill volumes that could have been significantly mitigated with prompt, effective incident identification and valve closure.

7. LIMITATIONS AND UNCERTAINTIES

There are limited data and information available for estimating costs and benefits. Table 7-1 summarizes the assumptions PHMSA made in the absence of data and the potential impact on the analysis.

Table 7-1. Uncertainties in the Analysis

Assumption or Limitation	Potential Impact	Comments
Number of operators/employees affected (100 percent)	Overstate costs	Some operators may already have response time standards or may be required to by state regulators. Not all pipeline operations personnel are involved in incident response procedures.
Level of effort to develop new rupture identification and response procedures (40 hours)	Overstate costs	Operators may be able to incorporate a procedure developed by an association or others.
Incremental post-incident analysis (40 hours)	Overstate costs	Operators are likely already conducting detailed analysis of some major ruptures.
Annual analysis costs based on the average number of ruptures per year	Uncertain	The number of ruptures could increase (e.g., from increased throughput or construction-related defects) or decrease (e.g., from increased program effectiveness).
Employment in the "other pipeline transportation" category that represents hazardous liquid pipeline operators (50 percent)	Uncertain	This category includes pipelines not regulated by PHMSA.
The distribution of new/replaced pipelines by size and location is based on existing infrastructure	Uncertain	The actual distribution may differ.
Baseline installation of ASVs/RCVs on new/replaced pipelines	Overstate costs	Future use could increase for a variety of reasons including state requirements, reduced costs, and increased benefits.
Operators must identify ruptures and close valves as soon as practicable but within 130 minutes	Overstate benefits	ORNL (2012) showed that benefits accrue with very rapid (e.g., 8 minutes) shut off of gas to enable quicker firefighting response.
Historical reported damages from hazardous liquid pipeline ruptures may not include all avoided costs	Understate benefits	Operators can submit a final accident report of environmental costs when long term remediation is still underway.
Number of operators who will request either to use alternative equivalent technologies as a substitute for an RMV	Overstate costs	Operators can request PHMSA approval to use alternative equivalent technology as a substitute for an RMV, thereby providing potential efficiencies and cost-savings.
Number of operators who will request exemption from RMV installation/operation requirements	Overstate costs	Operators can request exemption from certain requirements in the final rule
Number of operators who will request extensions of compliance timelines	Overstate costs	Operators can request extension of compliance timelines if required for economic, technical, or operational reasons.
Accidental Automatic Valve Closures	Understate costs	If the rule leads to more inadvertent ASV closures, there could be some unquantified costs to pipeline operators and their customers.

8. EVALUATION OF ALTERNATIVES

In developing the final rule, PHMSA considered a number of regulatory alternatives for rupture detection and mitigation, including:

- Exclusion of applicability to new gas pipeline in non-HCA Class 1 and Class 2 locations, in addition the final rule's requirements.
- Applicability to Type A and B gas gathering, versus only to Type A gas gathering pipelines.

In considering these alternatives, and the risks, costs, and benefits associated with ruptures and prompt valve closure, PHMSA selected the proposed rule requirements to address the congressional mandate. With respect to the retrofit of existing pipelines, PHMSA determined the scope to be beyond the intent of the Pipeline Safety Act of 2011 ("transmission facilities constructed or entirely replaced after the date on which the Secretary issues the final rule containing such requirement.").

The costs when non-HCA Class 1 and Class 2 gas pipelines are excluded are lowered only due to the fewer RMVs required (Table 8-1). About 1% of Class 1 and Class 2 mileage is in an HCA, thus substantially lowering the costs of equipment upgrades compared to the final rule. In contrast, adding Type B gas gathering pipelines adds very few new miles or pipelines and thus does not appear as an increase over the costs of the final rule (Table 8-2).

Table 8-1 and Table 8-2 show the resulting total cost estimates for these two alternatives.

Table 8-1. Annualized Costs when Class 1 and 2 Non-HCA Pipelines Are Excluded[1] (Millions 2020$)

System Type	Equipment Upgrades	Program Changes	Total
Gas pipeline	$0.6	$0.8	**$1.3**
Hazardous liquid pipeline	$3.0	$0.4	**$3.4**
Total	$3.7	$1.1	**$4.7**

Note: Detail may not add to total due to rounding.
1. Reflects 7 percent discount rate.

Table 8-2. Annualized Costs when Type B Gas Gathering Pipelines Are Included[1] (Millions 2020$)

System Type	Equipment Upgrades	Program Changes	Total
Gas pipeline	$1.9	$0.8	**$2.7**
Hazardous liquid pipeline	$3.0	$0.4	**$3.4**
Total	$5.0	$1.1	**$6.1**

Note: Detail may not add to total due to rounding.1. Reflects 7 percent discount rate.

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