DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191, 192, and 198

[Docket No. PHMSA–2021–0046]

RIN 2137–AF53

Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives

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

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: PHMSA proposes revisions to the pipeline safety regulations to require operators of gas distribution pipelines to update their distribution integrity management programs (DIMP), emergency response plans, operations and maintenance manuals, and other safety practices. These proposals implement provisions of the Leonel Rondon Pipeline Safety Act—part of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020—and a National Transportation Safety Board (NTSB) recommendation directed toward preventing catastrophic incidents resulting from overpressurization of low-pressure gas distribution systems similar to that which occurred on a gas distribution pipeline system in Merrimack Valley on September 13, 2018. PHMSA also proposes to codify use of its State Inspection Calculation Tool, which is used to help states determine the base-level amount of time needed for inspections to maintain an adequate pipeline safety program. Further, PHMSA proposes other pipeline safety initiatives for all part 192-regulated pipelines, including gas transmission and gathering pipelines, such as updating emergency response plans and inspection requirements. Finally, PHMSA proposes to apply annual reporting requirements to small, liquefied petroleum gas (LPG) operators in lieu of DIMP requirements.

DATES: Individuals interested in submitting written comments on this NPRM must do so by November 6, 2023.

ADDRESSES: Comments should reference Docket No. PHMSA–2021–0046 and may be submitted in any of the following ways:

E-Gov Web: https://www.regulations.gov. This site allows the public to enter comments on any Federal Register notice issued by any agency. Follow the online instructions for submitting comments.

Mail: Docket Management System: U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building Ground Floor, Room W12–140, Washington, DC 20590–0001.

Hand Delivery: DOT Docket Management System: West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, between 9:00 a.m. and 5:00 p.m. ET, Monday–Friday, except Federal holidays.

Fax: 202–493–2251

Instructions: Include the agency name and identify Docket No. PHMSA–2021–0046 at the beginning of your comments. Note that all comments received will be posted without change to *https://www.regulations.gov* including any personal information provided. If you submit your comments by mail, submit two copies. If you wish to receive confirmation that PHMSA received your comments, include a self-addressed stamped postcard.

Confidential Business Information: Confidential Business Information (CBI) is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (5 U.S.C. 552), CBI is exempt from public disclosure. If your comments in response to this NPRM contain commercial or financial information that is customarily treated as private, that you actually treat as private, and that is relevant or responsive to this NPRM, it is important that you clearly designate the submitted comments as CBI. Pursuant to 49 Code of Federal Regulations (CFR) 190.343, you may ask PHMSA to provide confidential treatment to the information you give to the agency by taking the following steps: (1) mark each page of the original document submission containing CBI as "Confidential;" (2) send PHMSA a copy of the original document with the CBI deleted along with the original, unaltered document; and (3) explain why the information you are submitting is CBI. Submissions containing CBI should be sent to Ashlin Bollacker, 1200 New Jersey Avenue SE, DOT: PHMSA–PHP–30, Washington, DC 20590–0001. Any comment PHMSA receives that is not explicitly designated as CBI will be placed in the public docket.

Docket: To access the docket, which contains background documents and any comments that PHMSA has received, go to *https://www.regulations.gov.* Follow the online instructions for accessing the docket. Alternatively, you may review the documents in person at DOT's Docket Management Office at the address listed above.

FOR FURTHER INFORMATION CONTACT: Ashlin Bollacker by phone at 202–680–8303 or by email at *ashlin.bollacker@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of the Regulatory Action

PHMSA proposes a series of revisions to the pipeline safety regulations (49 CFR parts 190–199) in response to congressional mandates and an NTSB recommendation, and to implement lessons learned from a September 13, 2018, incident resulting from the overpressurization of a low-pressure gas distribution pipeline operated by Columbia Gas of Massachusetts (CMA) in the Merrimack Valley. That incident resulted in one fatality, more than 20 people (including three first responders) being hospitalized, damage to approximately 130 structures, and an evacuation request for more than 50,000 residents. PHMSA expects the proposals of this NPRM will address the root causes and aggravating factors contributing to the severity of that incident and help reduce the frequency and consequence of other failure mechanisms on gas distribution pipeline systems. The proposals include improved design standards for low-pressure gas distribution systems; enhanced distribution integrity management program requirements; strengthened recordkeeping, planning, and monitoring practices for maintenance and construction activities on gas distribution systems; and improved emergency response communication and coordination protocols during emergency events for all 49 CFR part 192-regulated gas pipelines.[1] PHMSA also proposes codifying within the pipeline safety regulations its State Inspection Calculation Tool (SICT). The SICT is one of many factors used to help States determine the base-level amount of time needed for administering adequate pipeline safety programs, which PHMSA considers when awarding grants to States supporting those programs. PHMSA anticipates these proposed regulatory amendments will improve public safety, while also reducing threats to the environment (including, but not limited to, reduction of greenhouse gas emissions during incidents on gas pipelines), and promoting environmental justice for minority populations, low-income populations, or other underserved and disadvantaged communities, or others who are particularly likely to live and work near higher-risk gas distribution pipeline systems.

A catalyst for this rulemaking is the 2018 Merrimack Valley incident. The NTSB investigated the cause of this incident and issued a full report on its findings and safety recommendations.[2] The NTSB found the cause to be CMA's weak engineering management that failed to adequately plan and oversee a cast iron main replacement project. Contributing to the incident was CMA's low-pressure gas distribution system that was designed and operated without adequate overpressure protection. The NTSB reviewed other incidents from the past 50 years and found several previous incidents that involved high-pressure gas entering low-pressure gas systems. The NTSB found that a common cause of failure was an overpressure protection design scheme, common on older low-pressure distribution systems, that can be defeated by a single failure mode (*e.g.,* operator error or equipment failure). Currently, low-pressure gas systems are not required to have a device at the service location that would prevent the overpressurization of a customer's piping, fittings, and appliances, a required design feature on high-pressure distribution systems. Instead, overpressure protection on low-pressure distribution systems often is provided by a redundant design scheme (*i.e.,* worker and monitor regulators at the regulator stations). While overpressurizations on distribution pipelines are infrequent, they have the potential to be catastrophic given their location within population centers. As a result of its investigation, the NTSB recommended that PHMSA revise the pipeline safety regulations to address overpressure protection failures like that which occurred on CMA's low-pressure system.

In 2020, the Leonel Rondon Pipeline Safety Act was enacted as sections 202–206 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020, Pub. L. N 116–260). The law requires PHMSA to amend its regulations to ensure operators evaluate the risks associated with the presence of cast iron piping and the possibility of overpressurization on gas distribution systems through updates to their distribution integrity management program (DIMP). (49 U.S.C. 60109(e)(7)). The law further requires PHMSA to amend its regulations to ensure operators' emergency response plans include timely communications with first responders, public officials, customers, and the general public. (49 U.S.C. 60102(r)). PHMSA was also directed to amend its regulations to ensure operators' operations and maintenance (O&M) manuals include procedures for responding to overpressurization and a management of change (MOC) process with review and certification by relevant qualified personnel. (49 U.S.C. 60102(s)). PHMSA must also amend its regulations to ensure operators (1) keep ''traceable, reliable, and complete records;'' (2) monitor the gas pressure at district regulator stations during construction; and (3) assess and upgrade their district regulator stations to minimize the risk of overpressurization. (49 U.S.C. 60102(t)).

Pursuant to its statutory authority and in furtherance of its mission to protect people and the environment by advancing the safe transportation of energy and other hazardous materials essential to our daily lives, PHMSA proposes in this NPRM a number of regulatory amendments to implement those statutory mandates and NTSB recommendations arising from the 2018 CMA overpressure incident. PHMSA expects the proposed regulatory amendments to reduce the likelihood of another overpressure incident on low-pressure gas distribution systems similar to that which occurred in Merrimack Valley. PHMSA also expects the proposed amendments to reduce the frequency of, as well as public and environmental consequences from, failure mechanisms on gas distribution pipeline systems and other pipeline facilities. Additionally, this rulemaking aligns with the Administration's efforts to improve environmental justice and combat the climate crisis.[3] Older cast-iron or bare-steel gas distribution pipelines—a type of gas distribution pipeline particularly vulnerable to failure and overpressurization—are disproportionately concentrated in older, residential (often urban) areas with large minority, low- income, and other historically underserved and disadvantaged populations.[4] In addition, the reduced frequency and severity of incidents on gas pipelines anticipated from this rulemaking would have the benefit of minimizing the release of greenhouse gases from pipeline incidents—in particular methane—to the atmosphere.

The proposed rule is consistent with the goals of a new grant program established by the Bipartisan Infrastructure Law (BIL, enacted as the Infrastructure Investment and Jobs Act, Pub. L. 117–58). The new grant program, PHMSA's first ever Natural Gas Distribution Infrastructure Safety

[1] Part 192—regulated pipelines refers to gas distribution, transmission, and gathering pipelines, as applicable.

[2] NTSB, Accident Report PAR–19/02, ''Overpressurization of Natural Gas Distribution System, Explosions, and Fires in Merrimack Valley, Massachusetts, September 13, 2018'' (Sept. 24, 2019), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1902.pdf.*

[3] The White House Office of Domestic Climate Policy, ''U.S. Methane Emissions Reduction Action Plan,'' (Nov. 2021), *https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf.* This and other PHMSA rulemakings are identified in the U.S. Methane Emissions Reduction Action Plan as critical elements in the Federal government's efforts to address the climate crisis. *Id.* at 7–8 (listing PHMSA's Leak Detection and Repair rulemaking (proposed in 88 FR 31890 (May 18, 2023) (Leak Detection NPRM)), its Gas Gathering Final Rule (86 FR 63266 (Nov. 15, 2021)), its Valve Installation and Minimum Rupture Detection Standards Final Rule (87 FR 20940 (Apr. 8, 2022) (Valve Rule)), and its Gas Transmission Pipeline Safety Final Rule (87 FR 52224 (Aug. 24, 2022)).

[4] *See, e.g.,* Luna & Nicholas, ''An Environmental Justice Analysis of Distribution-Level Natural Gas Leaks in Massachusetts, USA,'' 162 Energy Policy 112778 (Mar. 2022); Weller et al., ''Environmental Injustices of Leaks from Urban Natural Gas Distribution Systems: Patterns Among and Within 13 U.S. Metro Areas,'' Environ. Sci & Tech. (May 11, 2022).

and Modernization grant program, authorizes $200 million a year in grant funding with a total of $1 billion in grant funding over the next five years. The grant funding is to be made available to a municipality or community owned utility (not including for-profit entities) to repair, rehabilitate, or replace its natural gas distribution pipeline systems or portions thereof or to acquire equipment to (1) reduce incidents and fatalities and (2) to avoid economic losses. The new grant program authorized by BIL can, however, address only part of the universe of at-risk distribution pipeline systems. While the grant program would assist eligible entities who receive funding in making needed repairs to their pipeline systems, PHMSA's proposal would go further in ensuring that all gas distribution and other part-192 regulated operators improve and maintain the safety of their systems and reduce the risk of public safety impacts and environmental damage from incidents on their pipeline systems.

B. Summary of the Proposed Regulatory Action

In this rulemaking, PHMSA proposes amendments to 49 CFR parts 191, 192, and 198. PHMSA also proposes compliance deadlines for each of the NPRM's regulatory amendments.

1. Clarifications and Updates to DIMP Plans—Part 192, Subpart P. Pursuant to 49 U.S.C. 60109(e)(7), PHMSA proposes several revisions to its DIMP regulations at 49 CFR part 192, subpart P. PHMSA further proposes that, subject to certain exceptions at § 192.1003, all gas distribution pipeline operators—including service lines—would need to update their DIMP plans in conformity with the amended requirements no later than one year after the publication of any final rule in this proceeding.

First, PHMSA proposes to require all operators of gas distribution pipeline systems identify and minimize the risks to their systems from specific threats in their DIMP. These specific threats, where applicable, include: (1) the presence of certain materials, such as cast iron and other piping with known issues; (2) overpressurization of low-pressure systems; and (3) extreme weather and other geohazards. Operators must also consider the effect of age on those specific threats faced by a distribution pipeline.

For operators of low-pressure gas distribution systems, PHMSA proposes that, when evaluating and ranking the above and other threats identified in their DIMP plans, operators must evaluate risks from: (1) abnormal operating conditions; and (2) potential consequences associated with low-probability events. If an operator can demonstrate through a documented engineering analysis, or an equivalent analysis incorporating operational knowledge, that no potential consequences are associated with a particular low-probability event, and therefore no potential risk exists, then the operator must notify PHMSA and state regulatory authorities of that determination within 30 days. Additionally, as part of the proposal to implement measures to minimize the risk of overpressurization, PHMSA would require operators of low-pressure distribution systems to identify, maintain, and obtain pressure control records. PHMSA would also require operators to identify and implement preventive and mitigative measures based on the unique characteristics of their system. If operators choose to implement measures to minimize the risk of an overpressurization on a low-pressure system, then they must notify PHMSA and state regulatory authorities no later than 90 days in advance of implementing any alternative measures. As an alternative to implementing such preventive and mitigative measures, operators could choose to upgrade their systems to meet new proposed design requirements applicable to new systems.

PHMSA is also proposing to omit operators of a liquefied petroleum gas (LPG) distribution pipeline system that serves fewer than 100 customers (small LPG operators) from the DIMP requirements. Based on recommendations from the National Association of Pipeline Safety Representatives (NAPSR), a National Academies of Science (NAS) study, and PHMSA's incident data, current DIMP requirements do not provide a safety benefit warranting the compliance burdens those requirements impose on small LPG operators and the administrative burdens placed on PHMSA and state regulatory authorities. Instead, PHMSA proposes to add a requirement for small LPG operators to complete an annual report providing data that would support PHMSA's regulatory oversight of the safety of those facilities.

2. Codifying in Regulation the Use of the State Inspection Calculation Tool—§§ 198.3 and 198.13. Consistent with 49 U.S.C. 60105(b) and 60105 note, PHMSA will update the SICT and proposes to revise its regulations to require that states use the SICT when ensuring an adequate number of safety inspectors are employed in their pipeline safety programs.[5] States would have to comply with these proposed changes no later than the next SICT update immediately following the effective date of any final rule in this proceeding. PHMSA proposes amendments to 49 CFR part 198 that would codify in regulation the SICT's use and define the terms ''State Inspection Calculation Tool'' and ''inspection person-days'' for the purposes of 49 CFR part 198.

3. Updates to Emergency Response Communications—§ 192.615. Pursuant to 49 U.S.C. 60102(a), PHMSA proposes a series of updates to its emergency response plan requirements that will be applicable to all operators of part 192-regulated gas pipelines. PHMSA also proposes certain emergency response plan requirements specific to gas distribution pipeline operators pursuant to 49 U.S.C. 60102(r). Unless a different compliance timeline is specified below, operators would need to update their emergency response plans in conformity with those amended requirements no later than one year after the publication of any final rule in this proceeding.

For all gas pipeline operators, PHMSA proposes to expand the existing list of pipeline emergencies in its regulations at § 192.615 for which operators must have procedures ensuring prompt and effective response by adding emergencies involving a release of gas that results in a fatality, as well as any other emergency deemed significant by the operator. In the event of a release of gas resulting in one or more fatalities, all operators must also immediately and directly notify emergency response officials upon receiving notice of the same. For distribution pipeline operators only, PHMSA's proposed expansion of the list of emergencies discussed above will also include the unintentional release of gas and shutdown of gas service to 50 or more customers (or 50 percent of its customers if it has fewer than 100 total customers); operators would need to immediately and directly notify emergency response officials on receiving notice of the same.

PHMSA also proposes regulatory amendments requiring gas distribution operators to update their emergency response plans to improve communications with the public during an emergency. First, PHMSA proposes to require gas distribution operators to establish and maintain communications with the general public as soon as practicable during an emergency. Second, PHMSA proposes to require gas

[5] The SICT can be accessed on the PHMSA Portal by authorized users.

distribution pipeline operators to develop and implement, no later than 18 months after the publication of any final rule in this proceeding, an opt-in system to keep their customers informed of the safety status of pipelines in their communities should an emergency occur.

PHMSA also seeks comment on whether it should require gas distribution operators to develop and implement emergency response procedures in accordance with incident command system (ICS) tools and practices. PHMSA also invites comment on the technical feasibility, practicability, and cost of immediate emergency notifications to customers via electronic text message or via a cellular phone application (''app'')—including both opt-in and opt-out notification approaches.

4. Updates to Operations and Maintenance Procedural Manuals—§ 192.605. Pursuant to 49 U.S.C. 60102(s), PHMSA also proposes a series of amendments to operations and maintenance (O&M) procedure manuals in § 192.605 that would require all gas distribution operators to implement within one year of the publication of any final rule issued in this proceeding. First, PHMSA proposes to require that operators of all gas distribution pipelines update their O&M procedures to account for the risk of overpressurization. PHMSA would require operators to have procedures for identifying and responding to overpressurization indications, including the specific actions and sequence of actions an operator would carry out to immediately reduce pressure or shut down portions of the gas distribution system, if necessary. PHMSA proposes that these O&M procedures would also describe investigating, responding to, and correcting the cause(s) of overpressurization indications.

Second, and again pursuant to 49 U.S.C. 60102(s), PHMSA proposes to require that operators of gas distribution pipelines develop and follow an MOC process when (1) installing, modifying, replacing, or upgrading regulators, pressure monitoring locations, or overpressure protection devices; (2) modifying alarm setpoints or upper or lower trigger limits on monitoring equipment; (3) introducing new technologies for overpressure protection into the system; (4) revising, changing, or introducing new standard operating procedures for design, construction, installation, maintenance, and emergency response; and (5) making any other changes that could impact the integrity or safety of a gas distribution system. Should any of these changes that an operator makes introduce a public safety hazard into the operator's gas distribution system, PHMSA proposes that the operator must identify, analyze, and control these hazards before resuming operations.

As part of the MOC process, PHMSA also proposes to require that gas distribution operators ensure qualified personnel review and certify construction plans associated with installations, modifications, replacements, or upgrades for accuracy and completeness, before the work begins. This amendment would ensure that qualified personnel—who are competently trained and experienced to identify system design and process deficiencies on gas distribution pipeline systems—provide oversight during the planning of those activities.

5. New Recordkeeping Requirements—§ 192.638. Pursuant to 49 U.S.C. 60102(t)(1), PHMSA proposes that all gas distribution pipeline operators identify and maintain traceable, verifiable, and complete maps and records documenting the characteristics of their systems that are critical to ensuring proper pressure controls for their gas distribution pipeline systems and to ensure that those records are accessible to anyone performing or supervising design, construction, and maintenance activities on their systems. PHMSA proposes to specify that these required records include (1) the maps, location, and schematics related to underground piping, regulators, valves, and control lines; (2) regulator set points, design capacity, and valve-failure mode (open/closed); (3) the system's overpressure protection configuration; and (4) any other records deemed critical by the operator. PHMSA proposes to require that the operator maintain these integrity-critical records for the life of the pipeline because these records are critical to the safe operation and pressure control of a gas distribution system. Operators would need to comply with this new requirement within one year of the publication of any final rule in this proceeding. If an operator does not have traceable, verifiable, and complete records as contemplated by this new requirement, then the operator must (1) identify and document which records they need, and (2) develop and implement procedures for generating or collecting those records, to include procedures for ensuring the generation or collection of those records. PHMSA also proposes that operators update these records on an opportunistic basis (*i.e.,* through normal operations, maintenance, and emergency response activities).

PHMSA expects that many gas distribution pipeline operators already have these records. Where they do not, these amendments would help to ensure that gas distribution pipeline operators improve the completeness and accuracy of their records. This amendment will also help to improve pipeline safety by ensuring operators provide appropriate personnel—such as qualified employees responsible for planning construction activities—with better, more complete, and more accurate records.

6. Monitoring of Gas Systems by Qualified Personnel—§ 192.640. Pursuant to 49 U.S.C. 60102(t)(2), PHMSA proposes that, where operators of gas distribution pipelines do not have the capability to remotely monitor pressure and either remotely or automatically shut off the gas flow at district regulator stations, operators must have qualified personnel on site to monitor certain construction projects so that they can prevent or respond to an overpressurization at a district regulatory station during those construction activities that have been determined to involve potential for such an event. Accordingly, PHMSA proposes requirements for all gas distribution operators to evaluate their construction projects to identify activities that could result in an overpressurization event at a district regulator station. If the operator identifies a potential for overpressurization due to a construction project, then the operator must ensure that at least one qualified employee or contractor is present during those activities that could result in a potential threat of overpressurization of the system. That qualified personnel would be responsible for monitoring the gas pressure in the affected portion of a gas distribution system and for promptly shutting off the gas flow to control an overpressurization event on the system. PHMSA is also proposing that operators must provide those qualified personnel with the location of all critical shutoff valves, pressure control records, and stop-work authority (unless prohibited by operator procedures) as well as the emergency response procedures, including the contact information of appropriate emergency response personnel. PHMSA proposes that gas distribution pipeline operators would need to comply with these requirements beginning one year after the publication of any final rule in this proceeding.

7. Requirements for New Regulator Stations—§§ 192.195 and 192.741. Pursuant to 49 U.S.C. 60102(t)(3), PHMSA proposes to require that

operators design new regulator stations on low-pressure distribution systems so there are redundant technologies installed to avoid or mitigate overpressurizations. Specifically, PHMSA proposes that all gas distribution operators, beginning one year after the publication of any final rule in this proceeding, equip all new, replaced, relocated, or otherwise changed district regulator stations serving low-pressure gas distribution systems with at least two methods of overpressure protection (such as a relief valve, monitoring regulator, automatic shutoff valve, or some combination thereof) that is appropriate for the configuration and siting of the station. Additionally, PHMSA proposes that operators minimize the risks from an overpressurization of a low-pressure system caused by a single event (such as excavation damage, natural forces, equipment failure, or incorrect operations) that either immediately or over time affects the safe operation of more than one overpressure protection device.

PHMSA also proposes to require that operators of low-pressure gas distribution systems monitor the outlet gas pressure at or near the district regulator station on such systems using a device capable of real-time notification to the operator of overpressurization. Low-pressure gas distribution operators are already required to have devices such as telemetering or recording gauges that record the gas pressure on their systems. However, some of these devices are not designed with the ability to provide real-time notification, and there is no explicit requirement that those devices be located near the district regulator station.

8. Construction Inspections for Gas Transmission Pipelines and Distribution Mains—§ 192.305. PHMSA proposes to amend § 192.305 to lift the indefinite stay of a regulatory amendment to that provision that had been introduced within a final rule issued on March 11, 2015.[6]

PHMSA also proposes an exception from this provision's inspection requirements for small gas distribution pipeline operators who would not be able to comply with the construction inspection requirement without using a third-party inspector. These regulatory amendments would, beginning one year after the publication of any final rule issued in this proceeding, apply to all other gas distribution pipelines operators; all gas transmission, all offshore gas gathering, and Type A gas gathering pipelines, and certain Types B and C gathering pipelines (specifically, those that are new, replaced, relocated, or otherwise changed).

9. Test Records—Clarification for Tests on Gas Distribution Systems—§§ 192.517 and 192.725. PHMSA proposes to amend § 192.517 to specifically identify the information that operators must record for tests performed on new, replaced, or relocated gas distribution pipelines and to ensure such records are available to operator personnel throughout the life of the pipeline. PHMSA proposes to amend § 192.725 to clarify that each disconnected service line must be tested in the same manner as a new, replaced, or relocated service line—that is, tested in accordance with 49 CFR part 192, subpart J—before being reinstated. PHMSA proposes to require that gas distribution operators comply with these amended testing recordkeeping requirements in connection with gas distribution pipelines that are new, replaced, or relocated beginning one year after the publication of any final rule in this proceeding.

10. Annual Reporting—§ 191.11. PHMSA proposes to add or expand annual reporting requirements for operators of gas distribution pipeline systems, including small LPG operators. For gas distribution pipelines, PHMSA proposes to collect additional information, such as the number and miles of low-pressure service lines, including their overpressure protection methods. For small LPG operators, these annual reports will collect information on the number and miles of service lines, and the disposition of any leaks. These proposed amendments will not apply to master meter systems, petroleum gas systems excepted from 49 CFR part 192 in accordance with § 192.1(b)(5), or individual service lines directly connected to production pipelines or gathering pipelines, other than a regulated gathering pipeline, as determined in § 192.8. PHMSA proposes that operators would need to comply with the above changes to annual reporting requirements beginning with the first annual reporting cycle after the effective date of any final rule issued in this proceeding.

11. Miscellaneous Amendments Pertaining to Part 192—Regulated Gas Gathering Pipelines—§§ 192.3 and 192.9. Following a decision by the U.S. Court of Appeals for the District of Columbia Circuit in litigation challenging application of requirements of PHMSA's April 2022 Valve Rule to gas and hazardous liquid gathering pipelines,[7] PHMSA issued a technical correction to the April 2022 Valve Rule codifying that decision.[8] PHMSA now proposes removal of certain exceptions introduced in the Technical Correction to restore, with respect to certain part 192-regulated gas gathering pipelines, application of specific regulatory amendments from the Valve Rule pertaining certain definitions (§ 192.3) as well as—by way of removal of exceptions within the regulatory cross-references at § 192.9—emergency planning and response (§ 192.615) and protocols for notifications of potential ruptures (§ 192.635).

C. Costs and Benefits

Consistent with 49 U.S.C. 60102(b) and Executive Order 12866 ''Regulatory Planning and Review,'' as amended by Executive Order 14094 ''Modernizing Regulatory Review'', PHMSA has prepared an assessment of the benefits and costs of the proposed rule as well as reasonable alternatives.[9] PHMSA expects that the rulemaking will yield significant public safety benefits associated with reduced frequency and severity of incidents similar to that which occurred in 2018 in Merrimack Valley, which resulted in a number of adverse consequences described in Section I.A. of this NPRM, as well as approximately $1.7 billion in property damage, lost gas, claims, other mitigation costs, and the social cost of methane emissions. PHMSA also expects that the proposed rule will yield other, unquantified benefits, which include improvements in risk reduction for pipeline leaks and incidents; reduced consequences from all incidents and emergencies; improved enforcement and oversight procedures; advanced safety measures and communications; avoided emissions; improved public confidence in the safety of gas pipeline systems; and associated environmental enhancements for populations, including those in historically disadvantaged areas. Cost savings reflect the removal of some requirements for small LPG operators. The costs of the proposed rule are attributed to new requirements and

[6] ''Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations,'' 80 FR 12762, 12779 (Mar. 11, 2015). PHMSA indefinitely stayed § 192.305 in response to a petition for reconsideration. *See* ''Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations: Response to Petitions for Reconsideration,'' 80 FR 58633, 58634 (Sept. 30, 2015).

[7] *GPA Midstream Ass'n* v. *Dep't of Transp.*, 67 F.4th 1188 (D.C. Cir. 2023).

[8] ''Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards: Technical Corrections,'' 88 FR 50056 (Aug. 1, 2023).

[9] 88 FR 21879 (Apr. 6, 2023); 58 FR 51735 (Oct. 4, 1993).

updates to operators' DIMPs, emergency response plans, operations and maintenance procedures, monitoring and inspection protocols, and other reporting and record-keeping proposals. The provisions include a range of proposals for primarily gas distribution operators, along with some proposals for other gathering and transmission operators.

PHMSA estimates the annualized costs of the proposed rule to be approximately $110 million per year at a 3 percent discount rate. In Table ES–1, below, PHMSA provides a summary of the estimated costs for the major provisions in this rulemaking and the total cost. For the full cost/benefit analysis and additional details on the summaries, please see the preliminary regulatory impact analysis (PRIA) in Docket No. PHMSA–2021–0046.

TABLE ES–1—TOTAL ANNUALIZED COSTS

[Millions, 2020$]

Proposed rule requirement	3% discount rate	7% discount rate
DIMP	$3.2	$4.3
Small LPG DIMP	−0.3	−0.3
SICT	0.0	0.0
Emergency response	1.0	1.2
O&M	42.8	44.7
Recordkeeping	24.3	27.8
Qualified personnel	34.8	34.8
District regulator stations	1.2	1.6
Inspections	0.04	0.05
Records: Tests	0.6	0.6
Annual Reporting	2.3	2.3
Total	110.0	117.1

Note: Costs annualized over 20 years.
Source: PHMSA analysis of gas distribution, transmission, and gathering operators, 2022.

PHMSA expects that each of the elements of the rulemaking, as proposed in this NPRM, will be technically feasible, reasonable, cost-effective, and practicable for the reasons stated in this NPRM and its supporting documents (including the PRIA and draft Environmental Assessment, each available in the docket for this rulemaking), and because the commercial, public safety and environmental benefits of those proposed regulatory amendments as described therein (reduced frequency and severity of incidents similar to the 2018 Merrimack Valley incident which bore an approximate cost of $1.7 billion in 2020$), would outweigh any associated costs and support PHMSA's proposed rule compared to alternatives.

II. Background

A. Gas Distribution Systems Overview

More than 2.3 million miles of gas distribution pipelines deliver gas to communities and businesses across the United States.[10] Gas distribution systems are made up of pipelines called ''mains,'' which distribute the gas within the system, and much smaller lines called ''service lines,'' which distribute gas to individual customers. Because the purpose of distribution pipelines is to deliver gas to customers, distribution pipeline systems are located predominantly in urban and suburban areas. Distribution pipelines are generally smaller in diameter than transmission pipelines and operate at lower pressures.

Risk to the public from gas distribution pipelines result from the potential for unintentional releases of the gas transported through the pipelines. Due to their proximity to populations, releases from distribution pipelines bear a particular risk to surrounding populations, communities, property, and the environment, and may result in death, injuries, and property damage.[11] Even small releases of natural gas can result in environmental harm, as methane (the primary constituent of natural gas) is a significant contributor to the climate crisis, with more than 25 times the impact on an equivalent basis as carbon dioxide.[12] While the overall trend in pipeline safety has steadily improved over the past two decades, gas distribution pipelines are still involved in a majority of serious gas pipeline incidents.[13] According to PHMSA's data, between 2003 and 2022, excavation damage was the leading cause of serious incidents along gas distribution pipelines (28 percent), followed by other outside force damage (23 percent) and incorrect operation (14 percent).[14]

Much of the Nation's gas distribution piping has been in the ground for a long time. Per PHMSA's gas distribution operator database, more than 50 percent of the nation's pipelines were constructed before 1970 during the creation of the interstate pipeline network built in response to the demand for energy in the post-World War II economy.[15] Historically, gas distribution pipelines were constructed from many different materials, including cast iron, steel, and copper. However, material fabrication and installation practices have improved since much of the Nation's gas distribution pipeline systems were installed, in acknowledgment that iron alloys like cast iron and steel degrade or corrode over time. Consequently, the age of a gas distribution system pipeline is an important factor in evaluating the risk it poses to public safety and the environment.

On April 4, 2011, following a string of major gas pipeline incidents, the Secretary of Transportation announced a Pipeline Safety Action Plan (Action Plan) that was a vehicle for Federal and State cooperation to accelerate the repair, rehabilitation, and replacement of the highest-risk pipeline infrastructure.[16] Efforts implementing the Action Plan focused on pipeline age and material as significant risk indicators. Pipelines constructed of cast- and wrought iron and bare steel were among those materials identified as posing the highest risk. In fact, operators of cast-iron and bare-steel distribution pipelines perform the vast majority of all leak repairs, despite these lines only making up about 21 percent of all distribution pipelines according to

[10] PHMSA, ''Annual Report Mileage for Gas Distribution Systems'' (June 1, 2022), *https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems.*

[11] This gas, regulated under 49 CFR parts 191 and 192, can be natural gas and any ''flammable gas, or gas which is toxic or corrosive.'' *See* §§ 191.3 and 192.3 (definitions of ''gas''). By way of example, in addition to natural gas, PHMSA regulates as a ''flammable gas'' over 1,500 miles of hydrogen gas pipelines. *See* PHMSA Interpretation Response Letter No. PI–92–030 (July 14, 1992) (noting PHMSA regulates hydrogen pipelines under 49 CFR part 192); PHMSA, ''Presentation of Vincent Holohan for Workgroup#4: Hydrogen Network Components at December 2021 Meeting'' at slide 11 (Dec. 1, 2021), *https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1227.* PHMSA consequently understands the proposed revisions to 49 CFR parts 191 and 192 within this NPRM would apply not only to natural gas pipelines but also to other gas pipeline governed by 49 CFR parts 191 and 192.

[12] U.S. Envtl. Prot. Agency, Global Methane Initiative: Importance of Methane (last updated June 9, 2022), *https://www.epa.gov/gmi/importance-methane#:~:text=Methane%20is%20more%20than%2025,due%20to%20human%2Drelated%20activities.*

[13] Serious incidents are those including a fatality or injury requiring in-patient hospitalization, excluding incidents when secondary ignition is involved, sometimes called ''fire first'' incidents. Between 2001 and 2020, gas distribution incidents comprised 81 percent of all the serious incidents reported to PHMSA. The three-year average incident count between 2018 and 2020 is 25, down from an average of 28 serious incidents between 2001 and 2020. ''Pipeline Incident 20 Year Trends'' (Nov. 15, 2022), *https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-20-year-trends.*

[14] ''Pipeline Incident 20 Year Trends'' (Nov. 15, 2022), *https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-20-year-trends.*

[15] PHMSA, ''By-Decade Inventory: Reports'' (Mar. 16, 2020), *https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/decade-inventory.*

[16] PHMSA, ''U.S. Transportation Secretary Ray LaHood Announces Pipeline Safety Action Plan'' (Apr. 4, 2011), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/dot4111.pdf.*

PHMSA's distribution operators' annual report data.[17]

Though the amount of cast and wrought iron pipe in use within gas distribution systems has declined significantly in recent years thanks to State and Federal safety initiatives and pipeline operators' replacement efforts, there are still approximately 20,000 miles of mains and 7,000 miles of service lines in the United States.[18] According to the U.S. Department of Energy, the total cost of replacing all cast iron and bare steel distribution pipelines in the United States would be approximately $270 billion.[19] PHMSA understands that both cost and practical barriers, such as urban excavation and disruption of gas supplies, can also limit replacement efforts. However, PHMSA finds that proactive management of the integrity of aging pipe infrastructure enhances safety and reliability, contributes to cost savings over the longer term, and can be less disruptive to customers and communities than a reactive approach. Accelerating leak detection, repair, rehabilitation, or replacement efforts also delivers the desired integrity and safety benefits more expeditiously, lowering maintenance requirements associated with the aging pipe that is being replaced.

There is no simple formula for determining which parts of the Nation's pipeline infrastructure should be of greatest concern. Factors often associated with higher risk include pipeline age, materials of construction, exposure to elements or outside forces, and an operator's practices in managing the integrity of its pipeline system. Each of these factors can contribute to a pipeline's risk, but effective integrity management can counterbalance the impact of aging and types of construction materials.

B. Gas Distribution Configurations

In a distribution system, gas is sourced from a transmission pipeline operating at a high pressure and must be safely delivered to the customer at lower pressures that are safe for customer piping and appliances. There are multiple points along the system where operators can reduce the pressure to be more suitable for the needs of the customer. City gate stations are the first such reduction point, and district regulator stations are pressure-reducing facilities downstream of city gate stations that further reduce the pressure from the pipeline coming from the city gate.[20] This lower pressure downstream of a district regulator station is more suitable for providing service to customers.

Each gas distribution system must be designed to operate safely at or below a certain pressure, also known as its maximum allowable operating pressure (MAOP), as determined in accordance with § 192.619. Exceeding this pressure can cause the gas to build up in the pipeline and potentially cause the failure of piping, joints, fittings, or customer appliances. As gas flows through a distribution system, devices called regulators control the flow of gas to maintain a constant pressure. If a regulator senses a drop or rise in pressure above or below a set point, it will open or close accordingly to adjust the pressure of gas. As an additional safety precaution against overpressurization, some distribution pipelines are also designed with a relief valve to vent the gas into the atmosphere. While modern gas regulators are highly reliable devices, they can fail due to physical damage, equipment failure (*e.g.,* degradation of materials such as seals and gaskets, defects or maintenance issues, or inability to control pressure as set), or the presence of foreign material in the gas stream.[21] Because there is the possibility of a regulator failing, distribution systems are typically designed with multiple means of protection and redundancies to reduce the likelihood of a catastrophic failure.

Many regulators require external control lines, which sense the outlet pressure of the regulator. Based on the pressure sensed through the control lines, the regulator valve will open or close to control the downstream pressure of the regulator. In some older installations, control lines are located farther downstream of the regulator station on the buried outlet piping based on either the manufacturer's recommendations or previous control-line standards and practices at the time of installation. However, a break in the control line (*e.g.,* if it is damaged during an excavation) will make the regulator sense a lower downstream pressure and will cause the regulator valve to open wider automatically. This could result in overpressurization of the downstream piping, which could lead to a catastrophic event. The same result occurs if the flow through the control line is otherwise disrupted, for example if the control line valve is shut off or if the control line is isolated from the regulator it is controlling.

In general, gas distribution pipeline systems can be classified as either low pressure or high pressure. In a high-pressure gas distribution system, the gas pressure in the main is substantially higher than what the customer requires, and a pressure regulator installed at each meter reduces the pressure from the main to a pressure that can be used by the customer's equipment and appliances. These regulators incorporate an overpressure-protection device to prevent overpressurization of the customer's piping and appliances should the regulator fail. Additionally, all new or replaced service lines connected to a high-pressure distribution system must have excess flow valves (see § 192.383). Excess flow valves can reduce the flow of gas through the service line by minimizing unplanned, excessive gas flows.[22]

In a low-pressure distribution system, the gas pressure in the main is substantially the same as the pressure provided to the customer (see § 192.3). Since a district regulator station located upstream of service lines acts as the primary means of pressure control in low-pressure distribution systems, an overpressurization in the system served by the district regulator could affect all the customers served by the system.

[17] Cast iron or bare steel pipelines account for 95 percent of corrosion leaks on mains, 92 percent of natural-force leaks on mains, 91 percent of pipe/weld/joint failure leaks; 97 percent ''other cause'' leaks on mains; and 76 percent of all known leaks. PHMSA, ''Cast and Wrought Iron Inventory'' (Apr. 26, 2021), *https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/cast-and-wrought-iron-inventory* (''Cast and Wrought Iron Inventory'').

[18] *See* Cast and Wrought Iron Inventory.

[19] U.S. Dep't of Energy, ''Transforming U.S. Energy Infrastructures in a Time of Rapid Change: The First Installment of the Quadrennial Energy Review'' at S–5 (Apr. 2015) *https://www.energy.gov/sites/prod/files/2015/08/f25/QER%20Summary%20for%20Policymakers%20April%202015.pdf.*

[20] ''At the city gate the pressure of the gas is reduced, and [this] is normally the location where odorant (typically mercaptan) is added to the gas, giving it the characteristic smell of rotten eggs so leaks can be detected.'' Pipeline Safety Trust, ''Pipeline Basics & Specifics About Natural Gas Pipelines'' at 4 (Feb. 2019), *https://pstrust.org/wp-content/uploads/2019/03/2019-PST-Briefing-Paper-02-NatGasBasics.pdf.*

[21] Gas may contain moisture, dirt, sand, welding slag, metal cuttings from tapping procedures, or other debris. Problems caused by such foreign material in the gas stream are most prevalent following construction on the pipeline supplying gas to the district regulator station. American Gas Association, ''Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event'' at 447 (Nov. 26, 2018).

[22] An excess-flow valve is a mechanical safety device installed on a gas service line to a residence or small commercial gas customer. In the event of damage to the gas service line between the street and the meter, the excess-flow valve will minimize the flow of gas through the service line. The pipeline safety regulations require a gas distribution company to install such a device on new or replacement service lines for single-family residences and certain multifamily and commercial buildings where the service line pressure is above 10 pounds per square inch gauge (psig). See 49 CFR 192.383 for specific requirements.

This is what occurred during the Merrimack Valley incident and is an inherent weakness of low-pressure gas distribution systems.

C. Merrimack Valley

On September 13, 2018, fires and explosions occurred after high-pressure natural gas entered a low-pressure natural gas distribution system operated by CMA, a subsidiary of NiSource, Inc.[23] One person, 18-year-old Leonel Rondon, was killed, and 22 people, including 3 firefighters, were transported to hospitals for treatment of their injuries. At least five homes were destroyed in the city of Lawrence and the towns of Andover and North Andover, MA, by the fires and explosions. More than 130 structures were damaged in total. Most of the damage occurred from fires ignited by natural gas-fueled appliances. More than 50,000 residents were asked to evacuate.

In response, fire departments from three municipalities were dispatched to the fires and explosions. First responders initiated the Massachusetts fire mobilization plan and received mutual aid from neighboring districts in Massachusetts, New Hampshire, and Maine. Emergency management officials had the electric utility shut off electrical power in the area. Additionally, CMA shut down its low-pressure natural gas distribution system, affecting 10,894 customers, including some outside of the affected area who had their service shut off as a precaution.

The NTSB on September 24, 2019, issued a final report of its investigation into the Merrimack Valley incident.[24] The NTSB found the cause of the incident was CMA's weak engineering management that failed to adequately plan, review, sequence, and oversee the construction project that led to the abandonment of a cast iron main without first relocating the regulator control lines to the new plastic main. The NTSB also found that contributing to the accident was CMA's low-pressure natural gas distribution system that was designed and operated without adequate overpressure protection.

D. Low-Pressure Gas Distribution System in South Lawrence

At the time of the incident, CMA owned and operated a network of gas pipeline systems for the transportation and delivery of natural gas that included approximately 25 different low-pressure gas distribution systems in Massachusetts. Among these systems, CMA owned and operated a low-pressure system in the area of South Lawrence, Massachusetts that served Lawrence, Andover, and North Andover, among other communities (South Lawrence system). The South Lawrence system was installed in the early 1900s and was constructed with cast iron and bare steel mains and used several regulator stations to control downstream pressure. The regulator stations were located below ground and contained regulators that monitored and controlled downstream pressure. Natural gas came into the South Lawrence system at a pressure of about 75 pounds per square inch, gauge (psig). The regulators reduced the pressure to about 0.5 psig for delivery to customers.

The South Lawrence system consisted of 14 regulator stations, wherein the regulator valves opened or closed based on the pressure the regulator sensed downstream to maintain the downstream pressure at a pre-set limit called a ''set point.'' This was to ensure the pressure in the system did not exceed the MAOP and become unsafe. Each regulator station in the South Lawrence system had at least two regulators in series—a ''worker regulator'' and a ''monitor regulator''—each with a control line that sensed downstream pressure and connected back to its regulator, thereby enabling the regulator station to regulate system pressure. The worker regulator was the primary regulator that maintained system pressure. The monitor regulator was the redundant backup in case the worker regulator was damaged or malfunctioned. If both control lines experienced a decrease in pressure, such as when the cast iron main was disconnected, the worker regulator and monitor regulator would automatically and continually increase the pressure, resulting in an overpressurization of the low-pressure system. That is precisely what occurred in CMA's gas main replacement project.

E. Gas Main Replacement Project

Beginning in 2016, CMA began a pipe replacement project in the South Lawrence system called the South Union Street project. CMA's field engineering department initiated the project in part due to the pending City of Lawrence water main project that would encroach on two aging cast iron mains on South Union Street. The construction project was also part of CMA's Gas System Enhancement Plan that called for replacing existing low-pressure cast iron pipelines (both mains and the accompanying service lines) with higher-pressure modern plastic piping.

The South Union Street project proposed replacing two low-pressure cast iron mains with one plastic high-pressure main. Once installed, the new plastic main would be ''tied-in'' to the distribution system and service lines supplying gas to customers. As is typical in pipe replacement projects, the two cast iron mains would be completely disconnected from the low-pressure system and abandoned in the ground upon completion.

The scope of the South Union Street project included the replacement of the cast iron mains near a belowground regulator station located at the intersection of Winthrop Avenue and South Union Street (the Winthrop regulator station), one of the 14 regulator stations that monitored and controlled downstream pressure in the South Lawrence system. Up until the time of the incident, two control lines connected the Winthrop regulator station and the two cast iron and bare steel mains on South Union Street.

CMA contracted with a pipeline services firm to complete the replacement project. CMA prepared a work package, which included materials such as isometric drawings and procedural details for disconnecting and connecting pipes, for each of the planned construction activities. However, CMA did not prepare a package for the relocation of the control lines serving the regulator station. The absence of a complete work package led to the contractor completing the installation of the plastic main with the regulator control lines at the regulator station still connected to the cast iron main that was being replaced.

In 2016, the construction crew installed the new plastic main on South Union Street and began feeding the new plastic main with gas from the Winthrop regulator station. However, CMA put the work on hold due to a city-wide moratorium on all gas, water, and sewer projects in Lawrence. Consequently, the construction crew was unable to begin any of the tie-in and abandonment procedures to tie-in or connect the mains or services to the new plastic main and thus was also unable to abandon the cast iron mains on South Union Street. The regulator control lines at the Winthrop regulator station remained connected to the cast iron mains that would ultimately be decommissioned.

The final stage of the South Union Street project involved the installation of tie-ins to the new plastic main, after which the legacy cast iron mains would be decommissioned and abandoned in

[23] CMA transferred from NiSource, Inc. to Eversource Energy in November 2020.

[24] NTSB/PAR–19/02 at 49.

their existing location. CMA then connected the plastic pipe to the gas distribution system, which allowed it to be monitored for pressure changes.

On September 13, 2018, at 4:00 p.m., the construction crew completed the final ''tie-in'' and abandonment procedure following the procedures CMA provided to the crew at South Union Street. Unbeknownst to the construction crew, the control lines were still connected to the abandoned cast iron main despite the gas now flowing through the new plastic main. At the Winthrop regulator station, about 0.5 miles south of the work area, the control lines that were still connected to the cast-iron mains on South Union Street sensed a sharp decline in pressure, causing the Winthrop regulator station to add more pressure into the South Lawrence low-pressure system. Feeding high-pressure gas into the low-pressure system resulted in a catastrophic overpressurization of the system. The overpressurization of the low-pressure system in the city of Lawrence and the towns of Andover and North Andover sent gas into home appliances at a rate that they were not designed to handle. This created explosions and fires in those homes and businesses. Local fire departments were the first to receive notification of the start of the incident via 9–1–1 calls. Shortly after 4:00 p.m., the local fire departments were inundated with calls from the public.

F. Emergency Response to the Merrimack Valley Incident

On September 13, 2018, the monitoring center in Columbus, OH, which was overseeing the CMA system, received pressure alarms on its supervisory control and data acquisition (SCADA) system.[25] The system recorded a sudden increase in pressure in the Merrimack Valley low-pressure system at 3:57 p.m. The SCADA's high-pressure alarms activated at 4:04 p.m. and 4:05 p.m. for the South Lawrence district regulator station and Andover, respectively. The SCADA system was only able to monitor system pressures; it could not remotely control the pressure of this system.

Following company protocol, at 4:06 p.m., the SCADA controller called the on-call technician in Lawrence, MA, and reported the high-pressure event. The on-call technician dispatched 3 field technicians to perform field checks on the 14 regulators within the South Lawrence system. Not until about 4:30 p.m. did a CMA field technician at the Winthrop regulator station (the location of the control lines still connected to the cast iron main) hear a loud sound and recognize that a large quantity of natural gas was flowing through the Winthrop regulator station. The CMA field technician adjusted the set point on the two regulators to reduce flow and isolated them. The CMA field technician then noticed that the sound of the flowing natural gas began to decrease.

Meanwhile, at 4:18 p.m., a CMA field engineer and a CMA field operations leader (FOL) were at another construction site when they received notice to respond to fire coming out of house chimneys. Due to traffic congestion, a police officer escorted the FOL to the construction site at Salem and South Union streets (location of the September 13 tie-in). When the FOL arrived at 5:08 p.m., crew members stated that they had confirmed the pressure in the entire low-pressure system was in the normal range before removing the bypass (*i.e.,* disconnecting the cast iron main from the Winthrop regulator station and connecting the new plastic main). At 5:19 p.m. the FOL took pressure readings at a nearby house and found the pressure was elevated. The FOL then recommended to a supervisor that CMA shut down the low-pressure system.

After being designated as the CMA Incident Commander by the Lawrence Operations Center manager, the FOL then called CMA's engineering department for the list of valves that needed closing to isolate and shut down the system. While waiting for this information, the FOL assigned crews to regulator stations and directed them to verify, with CMA's engineering department, the correct valve to close once they arrived at the regulator station. Once confirmed, they closed the valves. The FOL confirmed the closure of all valves at 7:24 p.m.

At 7:43 p.m., almost 4 hours after the CMA SCADA system detected the overpressurization, the president of CMA declared a ''Level 1'' emergency, in accordance with CMA's emergency response plan. According to the NTSB's report, the operator's Emergency Response Manual defines a ''Level 1'' emergency as a ''catastrophic event'' that includes the loss of a major natural gas facility or the loss of critical natural gas infrastructure.

Working through the night, CMA's engineering department worked under the FOL's direction to confirm that no gas was flowing into the regulator stations on the low-pressure system. On September 14, 2018, at 6:27 a.m., CMA confirmed the low-pressure distribution system was shut down for the 8,447 customers in the Lawrence, Andover, and North Andover areas. CMA shut down the natural gas to an additional 2,447 customers outside the immediate area as a precaution.

The following days required an unprecedented response effort. More than 50,000 residents were asked to evacuate from their homes following the overpressurization.[26] Thousands of homes needed to be entered, rendered safe, and secured to ensure that dangerous gas levels no longer existed. As the emergency response concluded, it was clear that the recovery effort would span months. CMA's work in the aftermath of the incident focused on repairing infrastructure damage, providing shelter, and finding longer-term housing solutions as recovery efforts extended into the fall and winter months.

The 2018 incident impacted three communities in the Merrimack Valley that, while geographically near one another, are different demographically. Lawrence is a densely populated city with many Spanish-speaking residents and a higher poverty rate than Andover and North Andover. Andover and North Andover are middle-class suburban communities, and although each has half the population size of Lawrence, their geographic size is four to five times that of Lawrence.

III. Recommendations, Advisory Bulletins, and Mandates

A. National Transportation Safety Board

The NTSB investigates serious pipeline accidents, including those that occur on gas distribution pipeline systems. The NTSB investigated CMA's overpressurization incident and issued its final report,[27] which included several findings and safety recommendations to NiSource, Inc., the Commonwealth of Massachusetts (Massachusetts), several other States,[28] and PHMSA.

[25] Operators use SCADA systems to monitor and control critical assets remotely. *See* § 192.631. Here, the South Lawrence system was monitored by CMA's corporate owner at the time, NiSource.

[26] Mass. Dep't of Pub. Utilities, ''Independent Assessment of Columbia Gas of Massachusetts' Merrimack Valley Restoration Program: Final Report,'' at A–2 (June 22, 2020), *https://www.mass.gov/doc/independent-assessment-of-columbia-gas-of-massachusetts-merrimack-valley-restoration-program/download.*

[27] *See* NTSB, PAR–19/02. The full report is available at *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1902.pdf.*

[28] These states were Alabama, Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Florida, Georgia, Idaho, Illinois, Kentucky, Louisiana, Maine, Maryland, Mississippi, Missouri, Montana, Nebraska, Nevada, New York, North Carolina, Pennsylvania, South Carolina, South

In its accident report, the NTSB issued two safety recommendations to PHMSA. The first, P–19–14, recommended that PHMSA require overpressure protection for low-pressure natural gas distribution systems that cannot be defeated by a single operator error or equipment failure. The NTSB further clarified that to satisfy this recommendation, PHMSA would not have to require that existing low-pressure gas distribution systems be completely redesigned; rather, PHMSA may satisfy this recommendation by requiring operators to add additional protections, such as slam-shut or relief valves, to existing district regulator stations or other appropriate locations in the system.[29] The second, P–19–15, recommended that PHMSA issue an advisory bulletin to all low-pressure natural gas distribution system operators of the possibility of a failure of overpressure protection. Further, P–19–15 stated that the advisory bulletin should recommend that operators use a failure modes and effects analysis or an equivalent structured and systematic method to identify potential failures and take action to mitigate those identified failures. In developing this NPRM, PHMSA also reviewed additional recommendations relating to the Merrimack Valley incident that NTSB made to states and operators.

B. Advisory Bulletins

1. Possibility of Overpressurization of Low-Pressure Distribution Systems Advisory Bulletin

On September 29, 2020, PHMSA issued an advisory bulletin (ADB–2020–02) to urge owners and operators of gas distribution systems to conduct a comprehensive review of their systems for the possibility of a failure of overpressure protection on low-pressure distribution systems.[30] The advisory bulletin addressed NTSB safety recommendation P–19–15, which underscored the elevated possibility of a common mode of failure on low-pressure distribution systems. Specifically, PHMSA requested owners and operators of low-pressure distribution systems to review the NTSB's report concerning the 2018 Merrimack Valley overpressurization event. PHMSA also recommended that operators review their current systems for a similar overpressure-protection configuration to that on the CMA pipeline involved in the incident. In the review of their systems, PHMSA urged operators to consider the possibility of a failure of overpressure-protection devices as a threat to their system's integrity. Additionally, PHMSA reminded owners and operators of their responsibilities under 49 CFR part 192, subpart P, to follow their DIMP and to revise their DIMP based on the new information provided in the NTSB's report and PHMSA's advisory bulletin. Finally, PHMSA recommended several ways that an operator can protect low-pressure distribution systems from an overpressurization event. Some examples include:

1. Installing a full-capacity relief valve downstream of the regulator station, including in applications where there is only worker-monitor pressure control;
2. Installing a ''slam-shut'' device;
3. Using telemetered pressure recordings at district regulator stations to signal failures immediately to operators at control centers; and
4. Completely and accurately documenting the location for all control lines on the system.

2. Cast-Iron Pipe Advisory Bulletin

On March 23, 2012, PHMSA issued advisory bulletin ADB–2012–05 to owners and operators of cast-iron distribution pipelines and State pipeline safety representatives.[31] PHMSA issued this advisory bulletin partly in response to the 2011 deadly explosions in Philadelphia and Allentown, PA, involving cast-iron pipelines installed in 1942 and 1928, respectively.[32] These incidents gained national attention and highlighted the need for continued safety improvements to aging gas pipeline systems. This advisory bulletin updated two prior advisory bulletins (ALN–91–02, issued on October 11, 1991, and ALN–92–02, issued on June 26, 1992 [33]) covering the continued use of cast-iron pipe in gas distribution pipeline systems. The ADB–2012–05 reiterated the two prior advisory bulletins, urging owners and operators to conduct a comprehensive review of their cast-iron gas distribution pipelines and replacement programs and to accelerate repair and replacement of high-risk pipelines. ADB–2012–05 also requested that State agencies consider enhancements to cast-iron replacement plans and programs. Specifically, in ADB–2012–05, PHMSA asked owners and operators of cast-iron distribution pipelines and State safety representatives to consider the following where improvements in safety are necessary:

1. Review current cast-iron replacement programs and consider establishing mandated replacement programs;
2. Establish accelerated leakage survey frequencies or leak testing;
3. Focus pipeline safety efforts on identifying the highest-risk pipe;
4. Use rate adjustments to incentivize pipeline rehabilitation, repair, and replacement programs;
5. Strengthen pipeline safety inspections, accident investigations, and enforcement actions; and
6. Install interior/home methane gas alarms.

PHMSA reminded owners and operators of their responsibilities under § 192.617 to establish procedures for analyzing incidents and failures to determine the causes of the failures and to minimize the possibility of a reoccurrence.

Finally, the advisory bulletin notes that the DOT, in accordance with the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112–90), will continue to monitor the progress made by operators to implement plans of safe management and replacement of cast-iron gas pipelines and identify the total miles of cast iron pipelines in the United States.

C. Statutory Authority

Title II of the PIPES Act of 2020, the ''Leonel Rondon Pipeline Safety Act,'' included several mandates for PHMSA to update the regulations governing operators of gas distribution systems. This NPRM addresses mandates codified at 49 U.S.C. 60102(r)–(t), 60105(b), and 60109(e)(7). (*See* sections 202, 203, 204, and 206 of the PIPES Act of 2020). Additionally, PHMSA has general statutory authority to regulate the safety of gas pipeline facilities subject to this rulemaking as discussed in section V.A of this NPRM.

Dakota, Texas, Utah, Virginia, and Wyoming. NTSB/PAR–19/02 at 50.

[29] NTSB clarified this in an official correspondence to PHMSA on July 31, 2020. NTSB, ''Safety Recommendation P–19–014'' (July 31, 2020), *https://data.ntsb.gov/carol-main-public/sr-details/P-19-014.*

[30] ''Pipeline Safety: Overpressure Protection on Low-Pressure Natural Gas Distribution Systems,'' ADB–2020–02, 85 FR 61097 (Sept. 29, 2020).

[31] ''Pipeline Safety: Cast Iron Pipe (Supplementary Advisory Bulletin),'' ADB–2012–05, 77 FR 17119 (Mar. 23, 2012).

[32] On January 18, 2011, an explosion and fire caused the death of one gas utility employee and injuries to several other people while gas utility crews were responding to a natural gas leak in Philadelphia, Pennsylvania. On February 9, 2011, five people lost their lives, several homes were destroyed, and other properties were impacted by an explosion and subsequent fire in Allentown, Pennsylvania.

[33] Research and Special Programs Administration (RSPA), ALN–91–02 (Oct. 11, 1991), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/RSPA%20Alert%20Notice%2091-02.pdf;* RSPA, ALN–92–02 (June 26, 1992), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/RSPA%20Alert%20Notice%2092-02.pdf* (supplementing ALN–91–02).

1. Distribution Integrity Management Program Plans and State Inspection Calculation Tool (49 U.S.C. 60109(e)(7) and 49 U.S.C. 60105(b) and 60105 Note; PIPES Act of 2020 Section 202)

PHMSA is required to issue regulations ensuring that DIMP plans for gas distribution operators include an evaluation of certain risks, such as those posed by cast iron pipes and mains and low-pressure distribution systems, as well as the possibility of future accidents to better account for high-consequence but low-probability events. (49 U.S.C. 60109(e)(7)). Gas distribution operators were required make their DIMP plans, emergency response plans, and O&M manuals available to PHMSA or the relevant State regulatory agency no later than December 27, 2022. Gas distribution operators must also make these documents, in updated form, available to PHMSA or the relevant State regulatory agency: (1) two years after the promulgation of regulations as required; and (2) every 5 years thereafter, as well as following any significant change to the document. PHMSA must also update and codify the use of the SICT, a tool used to help states determine the minimum amount of time it must dedicate to inspections. (*See* 49 U.S.C. 60105(b) and 60105 note).

2. Emergency Response Plans (49 U.S.C. 60102(r); PIPES Act of 2020 Section 203)

PHMSA is required to update its emergency response plan regulations to ensure that each emergency response plan developed by a gas distribution system operator includes written procedures for how to handle communications with first responders, other relevant public officials, and the general public after certain significant pipeline emergencies (49 U.S.C. 60102(r)). Specifically, the updated regulations would ensure that pipeline operators contact first responders and public officials as soon as practicable after they know a release of gas has occurred that resulted in a fire related to an unintended release of gas, an explosion, one or more fatalities, or the unscheduled release of gas and shutdown of gas service to a significant number of customers. Similarly, the updated regulations would provide for general public communication of pertinent emergencies as soon as practicable and leverage communications methods facilitating rapid notice to the general public.

3. Operation and Maintenance Manuals (49 U.S.C. 60102(s); PIPES Act of 2020 Section 204)

PHMSA is required to update the regulations for O&M manuals to require distribution system operators to have a specific action plan to respond to overpressurization events (49 U.S.C. 60102(s)). Additionally, operators must develop written procedures for management of change processes for significant technology, equipment, procedural, and organizational changes to their distribution system and ensure that relevant qualified personnel, such as an engineer with a professional engineer (PE) license, reviews and certifies such changes (49 U.S.C. 60102(s)).

4. Pipeline Safety Practices (49 U.S.C. 60102(t); PIPES Act of 2020 Section 206)

PHMSA is required to issue regulations that require distribution pipeline operators to identify and manage ''traceable, reliable, and complete'' maps and records of critical pressure-control infrastructure and update these records as appropriate. The records must be submitted or made available to the relevant regulatory agency (*i.e.,* PHMSA or the State). These regulations must require records to be gathered on an opportunistic basis. (49 U.S.C. 60102(t)(1)).

PHMSA must also issue regulations requiring a qualified employee of a distribution system operator to monitor gas pressure at district regulator stations and be able to shut off flow or limit gas pressure during construction projects that have the potential to cause a hazardous overpressurization. An exception to this requirement would be made for a district regulator station that has a monitoring system and capability for a remote or automatic shutoff (49 U.S.C. 60102(t)(2)). PHMSA is further required to issue regulations on district regulator stations to ensure that gas distribution system operators minimize the risk of a common mode of failure at low-pressure district regulator stations, monitor the gas pressure of low-pressure distribution systems, and install overpressure protection safety technology at low-pressure district regulator stations. If it is not operationally possible to install such technology, this section would require the operator to identify plans that would minimize the risk of overpressurization (49 U.S.C. 60102(t)(3)).

IV. Proposed Amendments

A. Distribution Integrity Management Programs (Subpart P)

In 2009, PHMSA issued a final rule titled ''Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines,'' creating 49 CFR part 192, subpart P.[34] As specified in § 192.1003, subpart P applies to operators of all gas distribution pipelines covered under part 192, subject to certain exceptions, and prescribes minimum requirements for integrity management programs for any such pipelines (referred to in this rulemaking as DIMPs). Adherence to a DIMP is an overall approach by operators to ensure the integrity of their distribution systems. The purpose of DIMP is to enhance safety by identifying and reducing pipeline integrity risks. DIMP regulations require that operators develop an integrity management plan that they must re-evaluate periodically; that integrity management plan complements operator efforts in complying with prescriptive operating and maintenance requirements elsewhere in part 192.

Pursuant to § 192.1007, DIMP regulations require operators implement the following steps in developing their DIMP plans:

(1) *Knowledge* (§ 192.1007(a))—Requires operators to understand their pipeline system's design and material characteristics, operating conditions and environment, and maintenance and operating history;

(2) *Identify Threats* (§ 192.1007(b))—Requires operators to identify existing and potential threats to their pipeline systems;

(3) *Evaluate and Rank Risk* (§ 192.1007(c))—Requires operators to evaluate and identify threats to determine their relative importance and rank the risks associated with their pipeline systems;

(4) *Identify and Implement Measures to Address Risks* (§ 192.1007(d))—Requires operators to determine and implement measures designed to reduce the risks from failure of their pipeline systems;

(5) *Measure Performance, Monitor Results, and Evaluate Effectiveness* (§ 192.1007(e))—Requires operators to measure the performance of their DIMPs and reevaluate threats and risks to their pipeline systems;

(6) *Periodic Evaluation and Improvement* (§ 192.1007(f))—Requires operators to periodically reevaluate threats and risks across the entire pipeline system; and

[34] 74 FR 63906 (Dec. 4, 2009).

(7) *Report Results* (§ 192.1007(g))—Requires operators to report their performance results to PHMSA and the applicable State agency through annual reports (required by § 191.11).

The first step in developing a robust DIMP plan, as required in § 192.1007(a), is for operators to have knowledge of their gas distribution system. PHMSA has clarified through enforcement guidance that this knowledge should include, but is not limited to, the following characteristics: location, material composition, piping sizes, joining methods, construction methods, date of installation, soil conditions (where appropriate), operating and design pressures, operating history, operating performance data, condition of system, and any other characteristics noted by operators as important to understanding their system. This information may be obtained from sources including system maps, construction records, work management system, geographic information systems (GIS), corrosion records, and personnel who have knowledge of the system (subject matter experts).[35] This step also requires operators to identify missing data and to develop a plan to collect relevant information as part of their normal pipeline activities over time.

The second step in developing and implementing a DIMP plan, as required in § 192.1007(b), is for operators to use the information they have gathered in compliance with § 192.1007(a) to identify threats to the integrity of their gas distribution systems. Section 192.1007(b) currently requires that operators consider eight broad categories of threats. These threats are corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other issues that could threaten the integrity of the pipeline.[36] Operators must consider reasonably available information to identify existing and potential threats. Sources of data may include incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience (see § 192.1007(b)).

Section 192.1007(b) requires operators to consider certain categories of threats and consider reasonably available information to identify other existing and potential threats not specifically listed. PHMSA has clarified through guidance that operators should use sources of information such as past O&M procedures, abnormal operating events, purchase orders, material lists from old field orders or standards, and information from industry sources (*e.g.,* plastic pipe database committee (PPDC),[37] NTSB accident reports, or PHMSA advisory bulletins) to help identify threats.[38] PHMSA identified potential threats that include, but are not limited to, non-leak events such as near misses, overpressurizations, and material and appurtenance failures. Even though certain potential threats may not have caused system integrity issues on an operator's particular system in the past, the fact that known industry or systemic risks exist requires operators to account for the threat in their DIMP. Further, operators should not eliminate any existing or potential threat to a system without an adequate basis for doing so.[39] PHMSA reiterated through guidance material that operators should consider environmental conditions that may be conducive to threats developing over time (*e.g.,* atmospheric corrosion, hurricanes, flooding, excavation damage, or materials with known integrity issues), so that operators do not eliminate potential threats without proper consideration.[40] Prior to excluding a potential threat, operators should perform an analysis of their records to ensure that the pipeline has not experienced the threat to date.[41]

PHMSA clarified through enforcement guidance that to exclude a threat from consideration, an operator should document the basis for that conclusion and should not exclude a threat based on the unavailability of information to support the existence of such a threat.[42] Where data is missing or insufficient, an operator should use a conservative assumption in the risk assessment. Operators must maintain records that identify how they use unsubstantiated data so that operators and regulators can consider the impact on the variability and accuracy of risk analysis results.[43]

The third step in developing and implementing a DIMP plan, as required in § 192.1007(c), is to evaluate and rank risk. Risk is the likelihood of an event occurring multiplied by the consequence of that event. An event that is highly likely and has significant public safety or environmental consequences constitutes an event of greatest concern, while an unlikely event that has minimal consequences may not justify any particular precautions. On the other hand, an unlikely event that could have very high consequences may justify special precautions. Incidents on gas distribution systems are generally low-likelihood, but high-consequence, events.

Risk analysis is an ongoing process of understanding the risk each identified threat presents to a pipeline. Operators use the threats identified in § 192.1007(b) and any knowledge gained when complying with § 192.1007(a) to evaluate the risks associated with their pipelines. Operators then must rank the risks to determine their relative importance. PHMSA has recommended that operators prioritize and address the risks of greatest concern first.[44]

The fourth step in developing and implementing a DIMP plan, as required in § 192.1007(d), is for operators to determine and implement measures designed to reduce the risks from failure of their gas distribution pipelines. These measures include having an effective leak management program (unless all leaks are repaired when found).[45] PHMSA's enforcement guidance specifies that the process for identifying risk reduction measures should be based on identified threats.[46] Operators

[35] PHMSA, ''Gas Distribution Pipeline Integrity Management Enforcement Guidance'' at 19–23 (Dec. 7, 2015), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/DIMP_Enforcement_Guidance_12_7_2015.pdf* (''DIMP Guidance'').

[36] PHMSA, ''F 7100.1–1, Annual Report: Gas Distribution System'' (May 2021), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2021-05/Current_GD_Annual_Report_Form_PHMSA%20F%207100.1-1_CY%202021%20and%20Beyond.pdf.*

[37] The Plastic Pipe Database Committee, composed of representatives of the American Gas Association (AGA), American Public Gas Association (APGA), Plastics Pipe Institute (PPI), National Association of Regulatory Utility Commissioners (NARUC), NAPSR, NTSB, and PHMSA, coordinates the creation and maintenance of a database to proactively monitor the performance of in-service plastic piping system failures and leaks with the objective of identifying possible performance issues.

[38] PHMSA, ''Gas Distribution Pipeline Integrity Management Enforcement Guidance'' at 19–23 (Dec. 7, 2015), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/DIMP_Enforcement_Guidance_12_7_2015.pdf* (''DIMP Guidance'').

[39] DIMP Guidance at 18–19.

[40] DIMP Guidance at 19.

[41] DIMP Guidance at 19.

[42] DIMP Guidance at 18–19.

[43] DIMP Guidance at 19, 58. Section 192.1011 requires that operators must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.

[44] DIMP Guidance at 22, 61.

[45] PHMSA notes that it recently proposed in a separate rulemaking a number of revisions to its prescriptive part 192 leak detection requirements that would *(inter alia)* require gas distribution to adopt advanced leak detection programs based on commercially available, advanced leak detection equipment. *See* ''Gas Pipeline Leak Detection and Repair,'' 88 FR 31890 (May 18, 2023).

[46] DIMP Guidance at 28.

should promptly identify the need for risk reduction measures if a new risk is identified.

Overall, DIMP requirements direct operators to identify conditions that can result in hazardous leaks or other unintended consequences and take actions to reduce the likelihood of the occurrence of a hazardous condition and the consequences of a resulting failure. It is critical for operators to identify threats that affect, or could potentially affect, a distribution pipeline to ensure that pipeline's integrity. Knowledge of applicable threats, whether actual or potential, allows operators to evaluate the safety risks they pose and to rank those risks, allowing the operator to apply safety resources where they will be most effective. For the most effective results, operators should break down these broad threat categories into more specific threats. An operator must use the knowledge of their system gained as a result of complying with § 192.1007(a), combined with the threats identified pursuant to § 192.1007(b), to perform a risk analysis to evaluate the likelihood and consequences of failures for those threats described in § 192.1007(c) for which risk-reduction measures are then identified and implemented under § 192.1007(d). The more accurately and completely an operator characterizes their system, the more accurate the risk analysis results will be. This in turn should inform how an operator allocates resources to mitigate the risks associated with its system.

Pipeline incidents since the promulgation of the DIMP rules in 2011 have demonstrated that some distribution operators whose systems are subject to DIMP requirements are not adequately identifying (step 2), evaluating (step 3), or mitigating (step 4) the threats that are degrading and reducing the integrity of their pipeline systems. For example, NTSB's report on the Merrimack Valley incident found that, by at least September 2015, CMA employees knew of overpressure dangers associated with maintenance on belowground control lines for low-pressure system regulator stations: a faulty, damaged, or unaccounted for control line could lead to overpressurization, resulting in fires and explosions in a populated area.[47] In September 2015, NiSource and CMA internally disseminated Operational Notice (ON) 15–05, titled ''Below Grade Regulator Control Lines: Caution When Excavating Near Regulator Stations or Regulator Buildings.''[48] The impetus for ON 15–05 was a ''near-miss'' experience involving another NiSource company outside of Massachusetts where a construction crew that was excavating to repair a gas leak near a regulator station came close to hitting a control line and was unaware of its purpose and importance. The NTSB's report concludes that even though NiSource had historically identified overpressurization as a threat in at least some of its internal procedures, NiSource had nevertheless failed to undertake a systemic evaluation (*e.g.,* a failure modes and effects analysis) of the risks associated with that threat and the mitigating actions needed to manage those risks.[49]

More robust risk management was also needed in the planning of the South Union Street project, particularly with respect to the threat of overpressurization. NTSB concluded that NiSource's engineering package for that construction project failed to identify, and control for the vulnerability of its system to, a common mode of failure during the construction project that could result in an overpressurization. After the incident in the Merrimack Valley, NiSource worked to improve its risk management processes and installed automatic pressure-control equipment.[50] Therefore, the NTSB concluded that NiSource's engineering risk management processes were deficient.

Subsequent to the Merrimack Valley incident, 49 U.S.C. 60109(e)(7) was amended to require PHMSA to add more specificity to the DIMP requirements to ensure that operators consider specific threats to their systems. Specifically, PHMSA must update its regulations to ensure DIMP plans for distribution operators include an evaluation of certain risks, such as those posed by cast iron pipes and mains and low-pressure distribution systems, as well as the possibility of future accidents, to better account for high-consequence but low-probability events. Distribution operators must make their updated DIMP plans available to PHMSA or the relevant State regulatory agency two years after any final rule in this proceeding is issued and every 5 years thereafter, as well as following any significant change to an operator's DIMP plan or distribution system.[51]

Another recent incident that illustrates operator failure to adequately identify, evaluate, and rank risk is a series of leaks and explosions that occurred on a gas distribution system operated by Atmos Energy Corporation between February 21, 2018, and February 23, 2018, in Dallas, TX. The NTSB investigated the February 2018 incident.[52] As specified by the NTSB, although Atmos' DIMP plan was consistent with the currently applicable minimum requirements, their plan did not adequately address the inherent risks of its 71-year-old system. In addressing the likelihood of failure, the age of a pipe is generally recognized as an important performance factor.[53] Currently, PHMSA's regulations do not explicitly require gas distribution operators to consider the age of their pipelines under a DIMP. Instead, PHMSA's regulations in § 192.1007(c) state that ''[a]n operator may subdivide its pipeline into regions with similar characteristics (*e.g.,* contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.'' Similar to what is described in PHMSA's regulations, Atmos grouped its assets into failure families based on asset attributes, such as material and coating. This method of evaluating the risks proved to be inadequate, given the high number of leaks observed that were due to the degradation of their pipelines over time.

Following the Atmos incident, NTSB issued recommendation P–21–2 to PHMSA.[54] This recommendation requires PHMSA to evaluate industry's implementation of DIMP requirements and to develop updated guidance for improving the effectiveness of operator DIMP plans. The recommendation goes on to say that the evaluation should ''specifically consider factors that increase the likelihood of failure such as age, increase the overall risk (including factors that simultaneously increase the likelihood and consequence of failure), and limit the effectiveness of leak management programs.''

[47] NTSB/PAR–19/02 at 18.

[48] NTSB/PAR–19/02 at 59–61.

[49] NTSB/PAR–19/02 at 40.

[50] NTSB/PAR–19/02 at 43.

[51] This provision also requires that operators make their current DIMP plans, emergency response plans, and O&M manuals available to PHMSA or the relevant State regulatory agency no later than December 27, 2022, which PHMSA intends to continue to review as appropriate in the course of inspection. *See* 49 U.S.C. 60109(e)(7).

[52] NTSB, Accident Report PAR–21/01, ''Atmos Energy Corporation Natural Gas-Fueled Explosion: Dallas, Texas: February 23, 2018'' (Jan. 12, 2021), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR2101.pdf.*

[53] NTSB/PAR–21/01 at 66.

[54] NTSB/PAR–21/01 at 72.

In this NPRM, PHMSA proposes to revise DIMP requirements so that operators of gas distribution systems will improve their identification of existing and potential threats to their pipelines' integrity, improve the accuracy of their risk analyses, and take meaningful, timely actions to remediate or mitigate the highest risks to their infrastructure. When developing the proposals in this NPRM, PHMSA considered applicable statutory mandates and the NTSB recommendations that followed the CMA and Atmos incidents. The proposals described in the paragraph's below apply to all gas distribution operators, including individual service lines (also known as farm taps),[55] but excluding small LPG operators. PHMSA discusses the proposal to remove small LPG operators from DIMP in IV.A.7.

Based on its review of the evidence in the record, PHMSA expects the proposed amendments to the DIMP requirements would be reasonable, technically feasible, cost-effective, and practicable for gas distribution operators. As explained above, these operators are already required by PHMSA regulations to have DIMPs for (*inter alia*) identifying threats to pipeline integrity, evaluating the risks of those threats, and implementing mitigation measures to manage those risks. The NPRM's proposed amendments would clarify baseline expectations for implementation of those existing DIMP elements consistent with historical PHMSA guidance, industry operational experience and research, and statutory mandates in the PIPES Act of 2020, enacted after the Merrimack Valley incident. Said another way, the NPRM's proposed revisions are consistent with the actions reasonably prudent gas distribution operators would undertake in ordinary course in implementing current DIMP requirements on gas distribution pipelines transporting pressurized (natural, flammable, toxic, or corrosive) gasses that are typically in close proximity to, or within, population centers. Within the guardrails proposed herein, operators would retain the significant flexibility contemplated by current DIMP regulations for operators to design and implement their DIMPs in a manner appropriate for managing integrity risks on their specific pipeline facilities while minimizing compliance costs. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their DIMPs and manage any related compliance costs.

1. DIMP—Identify Threats (§ 192.1007(b))—Materials

a. Current Requirements—DIMP—Identify Threats—Materials

Section 192.1007(b) requires operators to consider the general threat category of ''material or welds,'' but the requirement does not state that operators must consider specific material types and how each type could pose a threat to the integrity of a system. PHMSA has clarified through enforcement guidance that operators should consider subcategories of ''material'' threats to better categorize their pipelines by age or specific pipe type (such as bare steel, cast iron, wrought iron, and plastic piping) to focus on the root cause of potential failures.[56] PHMSA has also issued advisory bulletins alerting operators of threats related to specific material types, including cast iron (ADB–2012–05) and plastic piping (ADB–07–01 and ADB–2012–03).[57] PHMSA's annual report form, PHMSA F 7100.1–1 (see 49 CFR 191.11), also requires operators to identify specific subtypes of materials and the pipeline mileage of each.

b. Need for Change—DIMP—Identify Threats—Materials

Different piping materials could pose different threats to gas distribution systems and should be identified prior to conducting a risk analysis of those threats. All things equal, pipelines that are made of certain materials, like cast iron, wrought iron, bare steel, unprotected steel, and certain plastic pipelines, are more susceptible to leaks and other pipeline integrity issues. In particular, cast-iron pipe was the subject of an advisory bulletin (ADB–2012–05) that reiterated two alert notices previously issued by PHMSA that addressed the continued use of cast- and wrought-iron pipe in gas distribution pipeline systems and reminded owners and operators and State pipeline safety representatives of the need to maintain an effective cast-iron management program.[58] Similar to cast- and wrought-iron piping, steel pipelines without corrosion protection coating—also known as bare-steel or unprotected pipelines—are made of a material that could be a threat to a gas distribution system, as that material is more susceptible to corrosion than coated steel.

Certain vintages and types of plastic piping are also known throughout the industry to present acute threats to pipeline integrity. For example, susceptibility to premature brittle-like cracking of certain Aldyl ''A'' pipe, along with other vintages and manufacturers' products, is a well-documented problem in the industry and the subject of the advisory bulletin ADB–07–02. In this advisory bulletin, PHMSA recommended that operators consider the threat of brittle-like cracking applicable to any Aldyl ''A'' pipe in service (under the general category of ''material''), regardless of whether the threat had resulted in leakage to date. Similarly, PHMSA also alerted operators to the risks of material degradation on Driscopipe8000 (Driscopipe Series 8000 high-density poly-ethylene (HDPE)) pipe in Arizona and Nevada in ADB–2012–03.

While many of these pipelines have been taken out of service, some of them continue to operate today. As discussed earlier, the Merrimack Valley incident involved the replacement of cast-iron and bare-steel pipelines with modern plastic piping. This was part of CMA's pipeline replacement program, which called for the replacement of leak-prone low-pressure cast iron pipelines (both mains and services) with modern plastic pipe. Many operators are also engaged in pipeline replacement projects in response to PHMSA's Action Plan; managing the reduction in cast- and wrought-iron inventory has been a priority and in progress for many years.

Following the Merrimack Valley incident, PHMSA was required by

[55] An individual gas service line directly connected to a gas transmission, production, or gathering pipeline is commonly referred to as a ''farm tap.'' Individual service lines have the option of following either § 192.740, for service lines that are *not* operated as part of a distribution system, or DIMP (as detailed in § 192.1003(b)) for any portion of the individual service line that is classified as a service line. This rule proposed no change to this scope. The proposals apply to those individual service lines (aka farm taps) that apply DIMP.

[56] DIMP Guidance at 20.

[57] ''Pipeline Safety: Cast Iron Pipe (Supplementary Advisory Bulletin),'' ADB–2012–05, 77 FR 17119 (Mar. 23, 2012); ''Pipeline Safety: Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation,'' ADB–2012–03, 77 FR 13387 (Mar. 6, 2012); ''Updated Notification of Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe,'' ADB–07–02, 72 FR 51301 (Sept. 6, 2007).

[58] RSPA, ALN–92–02 (June 26, 1992); RSPA, ALN–91–02 (Oct. 11, 1991).

statute to ensure that operators evaluate the risk of the presence of cast iron in their DIMP plans. While only cast-iron was specifically identified as a material warranting explicit mention in DIMP regulations,[59] PHMSA understands that the Merrimack Valley incident (which occurred on a pipeline with both cast iron and bare steel) underscores that other types of high-risk materials on gas distribution systems warrant similar treatment. Although operators are already identifying what specific piping materials are on their system,[60] and § 192.1007(b) requires operators to actively monitor and consider the presence of piping material with known issues under the general threat category of ''material or welds,'' PHMSA believes that clarifying this practice in the DIMP regulations would ensure that as operators implement their DIMP plans, they consider the risks associated with the presence of these leak-prone materials, as required by the risk analysis in § 192.1007(c).

c. Proposal To Amend § 192.1007(b)—DIMP—Identify Threats—Materials

PHMSA proposes to revise § 192.1007(b) to clarify that operators must identify the threats posed by specific material types in their pipeline system, such as cast iron, wrought iron, bare steel, and historic plastic pipe with known issues. PHMSA expects that, in determining whether a plastic pipe material is a ''historic plastic with known issues'' representing a threat to pipeline integrity, operators should consider PHMSA and State regulatory actions and industry technical resources identifying systemic integrity issues on plastic pipe made from particular materials manufactured at particular times or by particular companies, or fabricated and installed pursuant to particular processes. As noted above, PHMSA issues advisory bulletins cautioning operators regarding the susceptibility of certain historic plastic pipelines to systemic integrity issues. Similarly, State pipeline safety regulatory actions, PHMSA pipeline failure investigation reports, and NTSB findings can inform operator determinations whether historic plastic pipe is at a high-risk loss of integrity. Industry efforts and resources are another resource for operators in determining whether historic plastic pipe has known issues. For example, the PPDC publishes periodic status reports of data submitted by program participants that incorporates information regarding investigations of materials of concern or potential concern.[61] PHMSA expects that these and other authoritative resources—coupled with an operator's own design expertise and operational and maintenance history—would be adequate for a reasonably prudent operator to determine whether the particular plastic pipe in its distribution system is a historic plastic with known issues. PHMSA further invites comment on whether, within a final rule in this proceeding, there would be value (in addition to being cost-effective, practicable, and technically feasible) in either explicitly listing (within subpart P or periodically-issued implementing guidance) historic plastics prone to leakage, or deleting the scope qualification ''historic'' from proposed regulatory text.

Once the threats are identified under § 192.1007(b), operators are also required to evaluate these risks under § 192.1007(c) and to ensure that risk reduction measures are identified and implemented under § 192.1007(d).

2. DIMP—Identify Threats (§ 192.1007(b))—Overpressurization

a. Current Requirements—DIMP—Identify Threats—Overpressurization

Section 192.1007(b) does not explicitly require operators to consider the threat of overpressurization as a threat under their DIMP plans. Instead, § 192.1007(b) requires operators to consider the general threat category of ''incorrect operations'' or ''other issues that could threaten the integrity of [a] pipeline'' and requires operators to consider whether those threats exist on their systems. However, overpressurization is a potential threat to gas distribution systems. PHMSA has stated through previous enforcement guidance and an advisory bulletin (ADB–2020–02) that overpressurization is a threat, especially for low-pressure gas distribution systems, and recommended that operators identify overpressurization as a threat in their DIMP plans. Further, § 192.195 provides design requirements for the protection against accidental overpressurization, including additional requirements for distribution systems.

b. Need for Change—DIMP—Identify Threats—Overpressurization

The threat of overpressurization, particularly on low-pressure gas distribution systems, is a threat that PHMSA expects operators to consider in their DIMP plans. PHMSA considers the threat of overpressurization to fall under the threat categories of both ''incorrect operations'' and ''other issues that could threaten the integrity of [a] pipeline'' in § 192.1007(b). In enforcement guidance, PHMSA lists ''overpressurization events'' as an example of potential threats operators could experience on their pipelines.[62] PHMSA also requires operators to have sufficient knowledge of their systems, per § 192.1007(a), to determine if overpressurization is a threat on their specific systems and to develop and implement measures to mitigate the consequences of a potential overpressurization. As discussed earlier, PHMSA also issued an advisory bulletin (ADB–2020–02) alerting operators of low-pressure gas distribution systems of the increased risk of overpressurization on those systems and recommended that operators consider the threat of overpressurization in their DIMP plans.

Recent incidents underscore the importance of operators adequately identifying the risk of overpressurization on distribution systems. Prior to the Merrimack Valley incident on September 13, 2018, the operator experienced four other overpressurizations and one ''near-miss'' within its network of distribution systems.[63]

On March 1, 2004, a system overpressurized when debris lodged at the seat of the bypass valve in Lynchburg, VA.

On February 28, 2012, an operator error during an inspection resulted in accidental overpressurization in Wellston, OH. 300 customers were without service for 14 hours.

On March 21, 2013, a segment of a pipe with an MAOP of 1 psig was pressurized at over 2 psig in Pittsburgh, PA. A work crew, under the direction of

[59] PHMSA notes, however, the threats to pipeline integrity posed by other materials. Specifically, 49 U.S.C. 60108 (Section 114 of PIPES Act of 2020) imposes a self-executing mandate on gas transmission, distribution, and part-192 regulated gas gathering pipeline operators to update their inspection and maintenance procedures to provide for replacement or remediation of pipelines ''known to leak based on their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues) . . . .'' PHMSA is considering within a separate rulemaking (under RIN 2137–AF54) whether to incorporate that self-executing statutory mandate within its 49 CFR part 192 regulations. *See* ''Gas Pipeline Leak Detection and Repair,'' 88 FR 31890 (May 18, 2023). PHMSA submits that this NPRM's amendments to DIMP requirements at subpart P would complement any revisions to prescriptive regulations elsewhere in 49 CFR part 192 that PHMSA may adopt in that parallel rulemaking.

[60] Operators are already subcategorizing their pipeline segments by material type (*i.e.,* cast iron, wrought iron, bare steel, and certain plastics with known issues) in their annual report form, PHMSA F 7100.1–1. *See supra* note 36.

[61] AGA, ''Plastic Pipe Data Collection Initiative'', *https://www.aga.org/natural-gas/safety/promoting-safety/plastic-pipe-data-collection-initiative/* (last visited March 10, 2023).

[62] DIMP Guidance at 19, 59.

[63] NTSB/PAR–19/02 at 25.

the local NiSource subsidiary, was making a tie-in and failed to monitor the pressure and flow of the existing low-pressure natural gas distribution system during the tie-in process.

On August 11, 2014, a local NiSource crew in Frankfort, KY, was excavating to repair a leak located on the outside of a regulator station building. The crew uncovered and narrowly missed hitting the 1-inch control line and tap located on the 8-inch outlet pipeline. The crew was unaware of the purpose of the 1-inch line and called local measurement and regulation (M&R) personnel. The M&R personnel advised the crew of the purpose of a control line and what would have happened had the line been broken. As discussed earlier, in 2015 NiSource issued ON 15–05 in response to this near miss. ON 15–05 required that M&R personnel be consulted on all future excavation work done within 25 feet of a regulator station with sensing lines, other communications and/or electric lines critical to the operation of the regulator station, or buried odorant lines. On September 13, 2018 (the date of the Merrimack Valley incident), however, CMA did not follow those procedures or implement any preventive or mitigative measures as they should have if they were correctly following DIMP requirements.

On January 13, 2018, during the investigation of a service complaint, an overpressurization was discovered on a natural gas distribution system in Longmeadow, MA. The cause was associated with debris accumulation on both the worker and monitor regulator seats at a regulator station. Once the debris was removed, the pressure returned to normal. This event illustrates that, in some cases, an overpressurization can occur that does not cause a catastrophic failure of the entire system, but if the operator takes timely, mitigative action, the system can safely return to normal. Operators know debris accumulation at regulator stations can cause an overpressurization and can plan routine maintenance of regulator stations to remove debris or install a device to prevent the debris from reaching the regulator station. However, an operator must first recognize overpressurization as a threat to ensure that they allocate resources to address this threat.

While overpressurization is a threat that PHMSA expects operators to consider in their DIMP plans, the pipeline safety regulations do not explicitly state that operators must identify and evaluate the threat of overpressurization in their DIMP plans. Following the Merrimack Valley incident on September 13, 2018, PHMSA was required by law to ensure that operators evaluate the risk of overpressurization in their DIMP plans. PHMSA therefore proposes to amend § 192.1007(b) to explicitly require operators to identify overpressurization as a threat to low-pressure distribution systems. The proposal is intended to ensure that operators consider this risk on their system as required by the risk analysis in § 192.1007(c) and identify risk reduction measures in accordance with § 192.1007(d).

c. Proposal To Amend § 192.1007(b)—DIMP—Identify Threats—Overpressurization on Low-Systems

PHMSA proposes to amend § 192.1007(b) to create a new threat category of ''overpressurization on low-pressure systems.'' This change would ensure that consideration of risks under the DIMP regulations explicitly includes overpressurization of a low-pressure system as a threat. Once identified as a threat under § 192.1007(b), operators would also have to evaluate the likelihood and the potential consequences of such a failure, as required in § 192.1007(c), and ensure risk-reduction measures are identified and implemented under § 192.1007(d). PHMSA discusses the actions operators must take to implement § 192.1007(c) and § 192.1007(d) in subsection IV.A.5 and 6 of this preamble.

3. DIMP—Identify Threats (§ 192.1007(b))—Natural Forces

a. Current Requirements—DIMP—Identify Threats—Natural Forces Including Extreme Weather and Geohazards

Section 192.1007(b) requires operators to consider the general threat category of ''natural forces,'' but the requirement does not explicitly state what natural forces could pose a threat to the integrity of the system. Natural force damage occurs as a result of naturally occurring events, including: (1) earthquakes and landslides; (2) heavy rains and flooding; (3) high winds, tornadoes, or hurricanes; (4) temperature extremes; and (5) lightning.[64] Further, PHMSA has issued advisory bulletins alerting operators to threats related to natural forces such as land movement (*i.e.,* geological hazards or ''geohazards'' [65]) (ADB–2022–01 and ADB–2019–02), severe flooding (ADB–2019–01), snow and ice build-up (ADB–2016–03), and extreme temperatures (ADB–2012–03).[66]

b. Need for Change—DIMP—Identify Threats—Natural Forces Including Extreme Weather and Geohazards

A distribution pipeline system operates in a discrete environment due to the limited geographic scope of each individual system. The environment in which a system operates significantly affects the threats to pipeline integrity that it faces. Factors such as weather (dry or wet, hot or subject to freezing) can significantly shape the threats affecting individual distribution operators and the actions necessary to address those threats. Major climate trends, such as elevated average surface temperatures, more intense storm events, and flooding, can, independently and in combination, affect the reliability and integrity of the United States' gas distribution infrastructure. As climate change has made extreme weather more common, it is harder to categorize what types of environmental factors facing distribution pipelines are ''normal'' based on geography and historical averages alone.

While freezing weather once seemed like a problem reserved for northern regions of the United States, southern regions are also experiencing unseasonable and extremely cold weather. For example, in February of 2021, Texas experienced a winter storm that brought some of the coldest temperatures in its history.[67] Extremely cold weather can cause thermal contraction stress or fractures of pipelines due to the expansion of moisture trapped inside components. In addition, safety relief devices can malfunction due to icing or freezing.

Low temperatures and the accumulation of snow and ice also increases the potential for physical

[64] PHMSA, ''Fact Sheet: Natural Force Damage'' (July 23, 2014), *https://primis.phmsa.dot.gov/comm/FactSheets/FSNaturalForce.htm.*

[65] PHMSA also interprets natural hazards to include geohazards.

[66] ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,'' ADB–2022–01, 87 FR 33576 (June 2, 2022); ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,'' ADB–2019–02, 84 FR 18919 (May 2, 2019); ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,'' ADB–2019–01, 84 FR 14715 (Apr. 11, 2019); ''Pipeline Safety: Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems,'' ADB–2016–03, 81 FR 7412 (Feb. 11, 2016); ''Notice to Operators of Driscopipe 8000 High Density Polyethylene Pipe of the Potential for Material Degradation,''ADB–2012–03, 77 FR 13387 (Mar. 6, 2012). PHMSA notes that many of those advisory bulletins identify resources maintained by other Federal agencies that can assist pipeline operators in identifying and evaluating integrity threats to their pipelines.

[67] On February 16, 2021, Dallas, TX recorded temperatures as low as -2 °F.

damage to meters and regulators and other aboveground pipeline facilities and components. For example, ice forming on regulators or pressure relief devices can cause them to malfunction or stop working completely.[68] Exposed piping at metering and pressure regulating stations, at service regulators, and at propane tanks are at the greatest risk. On February 11, 2016, PHMSA issued advisory bulletin ADB–2016–03 alerting operators to the dangers of abnormal snow and ice buildup on gas distribution systems. PHMSA has issued four other advisory bulletins since 1993 on this same issue.[69]

Natural forces such as severe flooding, river scour, and river channel migration can also adversely affect the safe operation of a pipeline. These incidents can damage a pipeline as a result of additional stresses imposed on the pipe by undermining underlying support soils, exposing the pipeline to lateral water forces and impact from waterborne debris. Additionally, the proper function of valves, regulators, relief sets, pressure sensors, and other facilities normally above ground or above water can be jeopardized when covered by water. PHMSA has issued several advisory bulletins alerting operators to the dangers severe flooding, river scour, and river channel migration can impose on a pipeline, most recently in 2019 through ADB–2019–01 and again in 2022 through ADB–2022–01.[70] Sometimes flooding is seasonal and predictable; however, the Intergovernmental Panel on Climate Change (IPCC) predicts increases in the frequency and intensity of heavy precipitation, which will give rise to increased risk of flooding.[71] In some areas, climate change means higher average precipitation,[72] resulting in water saturation that inhibits the ability of soil to absorb extreme precipitation events. Climate change may, however, result in drought for other parts of the United States,[73] as lower average annual precipitation rates result in lower soil moisture—and therefore, less ability to absorb extreme precipitation events. Also, rainfall during the four wettest days of the year has increased about 35 percent, and the amount of water flowing in most streams during the worst flood of the year has increased by more than 20 percent.[74] For parts of the United States, spring rainfall and average precipitation are likely to increase and severe rainstorms are likely to intensify during the next century.[75] Each of these factors will tend to further increase the risk of flooding—operators must assess how this may impact the integrity of their pipelines.

Extremely high temperatures can also pose integrity threats to certain materials. In March 2012, PHMSA issued advisory bulletin ADB–2012–03 regarding the potential for degradation of Driscopipe8000 pipes, which were produced from 1979 through 1997.[76] All reported occurrences of in-service degradation and leaks related to Driscopipe8000 pipes were installed in the desert region of the southwestern United States, particularly in the Mojave Desert region in Arizona, California, and Nevada. The ambient temperatures in the southwestern United States are very high (typically over 100 degrees Fahrenheit) and may contribute to issues for plastic piping. Driscopipe Series 7000 and 8000 HDPE pipe exposed to prolonged elevated temperatures may degrade as a result of thermal oxidation. One of the largest producers of polyethylene piping products in North America, has noted that ‘‘the mechanism for this oxidation appears to be the depletion of the thermal stabilizer, which has been shown to occur over time in high ambient temperature conditions.’’ [77] PHMSA has reminded operators through ADB–2012–03 that they should monitor the performance of their plastic piping.

Following the Merrimack Valley incident, PHMSA reviewed its current DIMP regulations for areas where additional clarification could improve the safety of gas distribution pipelines. As climate change increases the frequency of extreme weather events and natural forces that can impact the integrity of pipelines, PHMSA proposes to add clarity to the DIMP regulations to ensure that operators are considering these threats when evaluating risks. Operators would, therefore, need to consider and take appropriate action to address the impacts of extreme weather as a threat, regardless of whether they had experienced such events in their pipelines' history, while still recognizing regional differences. PHMSA expects operators to continue evaluating reasonably available information regarding changing operating environments (*i.e.,* climate) and the regional impacts of extreme weather on their pipeline.

c. PHMSA's Proposal To Amend § 192.1007(b)—DIMP—Identify Threats—Natural Forces Including Extreme Weather and Geohazards

PHMSA proposes to amend § 192.1007(b) to specify that operators must include the threat of extreme weather and geohazards as subcategories under the threat category of ‘‘natural forces.’’ This amendment would ensure that operators consider the threat of extreme weather under the DIMP regulations. Once identified as a threat under § 192.1007(b), operators would be required to consider how potential extreme weather events could increase the likelihood of failure. They would also need to consider the potential consequences of such a failure, as required in § 192.1007(c), and ensure that they identify risk-reduction measures and implement them under § 192.1007(d). PHMSA expects that operators would not limit their

[68] Regulators must be adequately protected from obstructions such as dirt, insects, and ice. If the vent on a regulator becomes completely obstructed, then the regulator can either shut off the flow of gas to a customer or increase the pressure to the upstream pressure, causing possible failures.

[69] ‘‘Pipeline Safety: Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems,’’ ADB–11–02, 76 FR 7238 (Feb. 9, 2011); ‘‘Pipeline Safety: Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems,’’ ADB–08–03, 73 FR 12796 (Mar. 10, 2008); ‘‘Potential Damage to Pipelines by Impact of Snowfall, and Actions Taken by Homeowners and Others to Protect Gas Systems from Abnormal Snow Build-up,’’ ADB–97–01 (Jan. 24, 1997); ‘‘Pipeline Safety Advisory Bulletin; Snow Accumulation on Gas Pipeline Facilities,’’ ADB–93–01, 58 FR 7034 (Feb. 3, 1993).

[70] *See, e.g.,* ‘‘Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,’’ ADB–2016–01, 81 FR 2943 (Jan. 19, 2016); ‘‘Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes,’’ ADB–2015–02, 80 FR 36042 (June 23, 2015); ‘‘Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,’’ ADB–2015–01, 80 FR 19114 (Apr. 9, 2015); ‘‘Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding,’’ ADB–2013–02, 78 FR 41991 (July 12, 2013); ‘‘Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding,’’ ADB–11–04, 76 FR 44985 (July 27, 2011).

[71] IPCC, Seneviratne, S.I., N. Nicholls et al., ‘‘Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation'' at 113 (2012), *https://www.ipcc.ch/site/assets/uploads/2018/03/SREX-Chap3_FINAL-1.pdf.*

[72] U.S. Envtl. Prot. Agency, ‘‘What Climate Change Means for Missouri'', EPA 430–F–16–027, at 1 (Aug. 2016), *https://19january2017snapshot.epa.gov/sites/production/files/2016-09/documents/climate-change-mo.pdf* (noting that over the last half century, average annual precipitation in most of the Midwest has increased by 5 to 10 percent).

[73] *See* A. Park Williams et al., ‘‘Rapid Intensification of the Emerging Southwestern North American Megadrought in 2020–2021,'' 12 Nature Climate Change 232–234 (2022).

[74] U.S. Envtl. Prot. Agency, ‘‘What Climate Change Means for Missouri,'' at 1.

[75] U.S. Envtl. Prot. Agency, ‘‘Climate Impacts in the Midwest,'' Climate Change Impacts, *https://climatechange.chicago.gov/climate-impacts/climate-impacts-midwest* (last visited Feb. 25, 2023).

[76] 77 FR at 13388.

[77] Performance Pipe, ‘‘Driscopipe® 8000 Pipe Degradation in High Temperature Applications'' *https://www.cpchem.com/sites/default/files/2020-05/DriscopipeDegradation.pdf* (last visited Mar. 1, 2023).

consideration of the threat of extreme weather solely on past normal weather patterns but would also consider any anticipated increases in extreme weather conditions and fluctuations. This proposed requirement would improve safety by ensuring that operators address the impacts of climate change and protect the reliability and integrity of their pipeline systems, even if operators have yet to experience these issues on their systems.

4. DIMP—Identify Threats (§ 192.1007(b))—Age of the System, Pipe, and Components

a. Current Requirements—DIMP—Identify Threats—Age of the System, Pipe, and Components

Section 192.1007(b) includes a generic threat category of ''other issues that could threaten the integrity of [a] pipeline,'' which operators should use to identify threats that do not fit into the other threat categories. When performing their risk analysis, § 192.1007(c) states that operators ''may subdivide [their] pipeline into regions with similar characteristics.'' PHMSA has observed operators using age as a method of subdividing their pipeline segments when performing the risk analysis. Further, PHMSA's annual report form, PHMSA F 7100.1–1, requires operators to identify the miles of pipeline by decade of installation. Section 192.1007(b) does not, however, specifically require that operators consider the age of a pipe or components when identifying threats to pipeline integrity.

b. Need for Change—DIMP—Identify Threats—Age of the System, Pipe, and Components

Over time, all pipeline systems are subject to time-dependent degradation processes threatening pipeline integrity. Pipelines made from ferrous materials (steel, wrought iron, cast iron, etc.) are all susceptible to oxidation corrosion over time. Plastic and composite materials used in pipelines are subject to photodegradation if exposed to sunlight. Joints, fittings, and welds connecting various pipeline components can be subject to dissimilar materials corrosion or chemical degradation of bonding agents and sealants. And the longer the timeline, the more any gas pipeline components are exposed to a variety of phenomena—*e.g.,* from internal mechanical stresses, changes in temperature, changes in external loads (including external force damage)—that threaten pipeline integrity, exacerbate existing material weaknesses, or accelerate time-dependent degradation processes.

Age can impact and potentially modify each of the threats an operator identifies in § 192.1007(b). The potential threat to pipeline integrity posed by age depends on the age of the pipeline components of which it is comprised. PHMSA understands the cumulative effect of those age-related threats to integrity across an entire pipeline are not merely the sum of age-related, component-specific threats; rather, those threats can magnify or exacerbate one another when integrated within a pipeline system. For example, one component's failure due to time-dependent degradation processes can strain other components throughout the system (*e.g.,* by releasing corrosion products that can damage other, newer components within the system). PHMSA further notes that trending failure rates by age can be a useful tool for revealing degraded performance throughout a pipeline system.

Similarly, the overall age of the pipeline system can provide more opportunities for safety-critical gaps in material records. Poor recordkeeping with respect to a pipeline component dating from a certain time period may threaten not only pipeline integrity on that segment, but also other components of the same pipeline installed at a different time period.

Age can also be expressed in terms of vintage of pipes or components. Specific manufacturing techniques and materials used during certain periods of time can result in similar characteristics among pipes and components of a given vintage. The vintage of pipes or components can interact with other threats, including materials, equipment failures, or natural forces. For example, pipe installed earlier than 1950 has disproportionately high susceptibility to problems from cold weather and freezing, which could interact with the threat of natural forces. The greater susceptibility of pre-1950 pipe is thought to be due to inferior low-temperature ductility of the steels of the era and the methods used to join pipe at the time (such as electric arc welds, acetylene welds, couplings, and threaded collars).[78] Additionally, as described in section IV.A.1 (materials), some of the early plastic piping products manufactured from the 1960s and into the early 1980s are more susceptible to brittle-like cracking (also known as slow-crack growth) than newer materials.[79]

Even though time-dependent degradation processes are widely understood threats to the integrity of pipeline systems, as discussed earlier, § 192.1007(b) does not specifically state that operators must account for the age of the system, pipe, and components in identifying threats. Increasing failure rates have been observed in older gas distribution infrastructure that has certain attributes.[80] The increasing failure rate typically occurs toward the end of life and accelerates the rate by which the reliability decreases. This behavior is typically attributed to cumulative degradation that occurs in the system over its service period. Trending failure rates by system age can reveal degrading performance.

Recent incidents have illustrated that operators may be inadequately identifying and managing threats related to the age of components on their systems. For example, in its risk analysis, Atmos used a commercially available software that did not explicitly consider the age of the pipeline segments, instead grouping them into failure categories based on similar attributes, such as material and coating. Although such an approach may have been compliant with current regulations, this approach to risk analysis disregards how the age could contribute to failures. Following the 2018 Atmos incidents, the NTSB recommended that Gas Piping Technology Committee develop guidance and identify steps operators can take to ensure that their gas distribution IM programs appropriately consider threats that degrade a system over time.[81] By adopting such a practice, operators would recognize the full threat based on the impact of age and prioritize remediating or replacing segments of the pipe and components that pose more acute threats. PHMSA therefore proposes to revise § 192.1007(b) to explicitly identify age as a factor in addressing threats to integrity.

c. Proposal To Amend § 192.1007(b)—DIMP—Identify Threats—Age of the System, Pipe, and Components

PHMSA proposes to amend § 192.1007(b) to clarify that operators

[78] M.J. Rosenfeld, ''Cold Weather Can Play Havoc On Natural Gas Systems'' 242 Pipeline & Gas J. 1 (Jan. 2015), *https://pgjonline.com/magazine/2015/january-2015-vol-242-no-1/features/cold-weather-can-play-havoc-on-natural-gas-systems.*

[79] Brittle-like cracking failures occur under conditions of stress intensification. Stress intensification is more common in fittings and joints.

[80] PHMSA, ''Pipeline Replacement Background'' (Apr. 26, 2021), *https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/pipeline-replacement-background.*

[81] NTSB/PAR–21/01 at 82.

must, when identifying the threats on its distribution system, also consider the age of the system, piping, and components in identifying threats.[82] For example, once an operator identifies a time-dependent threat exists on their pipeline, such as corrosion, the operator would then consider how the age of the pipe, or the components, could influence the severity of the threat. All things equal, an older pipe or component exposed to the threat of corrosion could carry additional risk compared to newer pipe. Similarly, for time-independent threats, such as natural forces, the operator would consider how the age of the pipeline or components would expose the pipeline to multiple threats over its lifetime, a threat that may evolve or increase over time. PHMSA's proposal would ensure that the DIMP regulations explicitly account for how the age of the system, pipes, and components contribute to a pipeline's integrity degrading over time.

5. DIMP—Evaluate and Rank Risk (Section 192.1007(c))

a. Current Requirements—DIMP—Evaluate and Rank Risk

Section 192.1007(c) requires that operators evaluate and rank the risks associated with their distribution pipeline systems. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. Operators may subdivide their distribution systems into regions (areas within a distribution system consisting of mains, services, and other appurtenances) that have similar characteristics and reasonably consistent risks, and for which similar actions would be effective in reducing risk.

Through enforcement guidance, PHMSA recommended that operators develop weighted factors for each threat specific to their system depending upon their unique operating environment.[83] PHMSA has further stressed that it may be inadequate for operators to conclude that a pipeline is not subject to any particular threat based solely on the fact that it has not experienced a pipeline failure attributed to the threat.[84] PHMSA has used enforcement guidance to clarify that if operators conclude that a particular threat is not applicable to sections of their pipeline, then operators should document the basis for drawing that conclusion.[85] This basis should consider the pipeline's failure history, design, manufacturing, construction, operation, and maintenance.

b. Need for Change—DIMP—Evaluate and Rank Risk

Recent incidents have demonstrated the importance of operators adequately evaluating and ranking risks on their systems and in their DIMP plans. For example, as demonstrated by the 2018 Merrimack Valley and other incidents investigated by the NTSB, some operators have not been adequately evaluating the risk of overpressurization, and thus not taking appropriate mitigating measures to account for those risks.[86] Overpressurization incidents—in particular on low-pressure gas distribution systems—merit mitigation because they have a high-consequence. As previously noted, CMA had knowledge of the risks of an overpressurization, updated their procedures, and still did not take appropriate action to mitigate the risks. Similarly, the Atmos incident in Texas demonstrated how operators can underestimate the risks associated with the presence of leak-prone materials.

PHMSA is required by law to ensure that operators' DIMP plans evaluate the presence and risks associated with cast iron piping and the threat of overpressurization on low-pressure gas distribution systems (49 U.S.C. 60109(e)(7)). PHMSA is also required to prohibit operators, when evaluating risks related to the operation of a low-pressure gas distribution system, from determining that there are no potential consequences associated with low-probability events unless that determination is supported by ''engineering analysis or operational knowledge.'' PHMSA must also ensure that operators of gas distribution systems consider factors other than past observed ''abnormal operating conditions''—as that term is defined at § 192.803—when ranking risks and identifying measures to mitigate those risks.

c. PHMSA's Proposal To Amend § 192.1007(c)—DIMP—Evaluate and Rank Risk

PHMSA proposes to redesignate the general requirements of § 192.1007(c) under a new paragraph (c)(1). These general requirements still require operators to consider the identified threats proposed in § 192.1007(b) as they evaluate and rank risks.

i. Certain Pipe Materials With Known Issues

PHMSA proposes to amend § 192.1007(c) by creating a new § 192.1007(c)(2) to specify that operators must evaluate the risks resulting from pipelines constructed with certain materials (including cast iron, bare steel, unprotected steel, wrought iron, and historic plastics with known issues) when such materials are present in their pipeline systems. Overall, these proposed requirements would improve safety by codifying in DIMP requirements some of the known, industry-wide threats if the materials that have exhibited these threats are present in the operator's systems, even if operators have not yet experienced any of these issues on their systems.

ii. Evaluate and Rank Risk: Low-Pressure Distribution Systems

PHMSA also proposes to amend § 192.1007(c) by creating a new § 192.1007(c)(3) applicable to low-pressure distribution systems. Consistent with the mandate in 49 U.S.C. 60109(e)(7), PHMSA proposes to require operators of low-pressure gas distribution systems to evaluate ''the risks that could lead to or result from the operation of a low-pressure distribution system at a pressure that makes the operation of any connected and properly adjusted low-pressure gas burning equipment unsafe.'' For the purposes of this NPRM, PHMSA determines that ''unsafe'' in this context means that gas flowing into the downstream equipment is at a pressure beyond the rated supply pressure specified by the manufacturer of that equipment. This amendment would ensure that operators are addressing the risks on their pipeline that could result in an overpressurization.

In evaluating the risks to low-pressure distribution systems, the mandate in 49 U.S.C. 60109(e)(7)(B) requires PHMSA to ensure that operators consider ''factors other than past observed abnormal operating conditions [. . .] in ranking risks.'' This includes any abnormal operating conditions (AOCs) that operators have experienced (*i.e.,* observed) on their system and any unobserved AOCs that could occur on their system (*i.e.,* an overpressurization on a low-pressure system), including any known industry threats, risks, or hazards, as identified by an operator from available sources (*e.g.,* PHMSA advisory bulletins, PHMSA incident and accident reports, PHMSA and NTSB accident reports, State pipeline safety regulatory actions, and operator knowledge sharing). PHMSA proposes

[82] *See* Am. Soc'y of Mech. Eng's, ANSI B31.8S–2004, ''Managing System Integrity of Gas Pipelines,'' at sec. 2 (Jan. 14, 2005).

[83] DIMP Guidance at 22.

[84] DIMP Guidance at 23.

[85] DIMP Guidance at 18, 57.

[86] NTSB/PAR–19/02 at 18–21, 39–40, 48.

in § 192.1007(c)(3)(i) to require operators of low-pressure systems to evaluate risks to their systems in accordance with the mandate. This amendment would ensure that operators are reviewing their past observed operational performance to evaluate the risks on their systems. This amendment would also ensure that operators are considering risks even if they have yet to experience those risks on their systems. For example, if an operator has not experienced an overpressurization on its system, that operator must still consider the risks of an overpressurization on its system.

The mandate in 49 U.S.C. 60109(e)(7)(B) also states that operators may not determine that low probability events have no potential consequences without a supporting determination. PHMSA proposes integrating this mandate by adding a new paragraph § 192.1007(c)(3)(ii) that will direct operators to evaluate the potential consequences associated with low-probability events, unless a determination—supported and documented by an engineering analysis or other equivalent analysis incorporating operational knowledge—demonstrates that the event results in no potential consequences (and therefore no potential risk).

An engineering analysis would include documentation of the engineering principles used to calculate the flows, pressures, and other parameters of the piping and systems to calculate the actual downstream pressure. This engineering analysis would also include documentation of the methods used to determine that the system cannot fail and cause overpressurization, including any data and assumptions (including mitigation and control measures) utilized by the operator. This engineering analysis may necessarily include degrees of measurable operational knowledge regarding specific pipeline characteristics and evidence from that analysis combined with documentable known pipeline characteristics. An operator that determines there are no potential consequences from a low-probability event must document all these reasons as part of its ''engineering analysis'' submitted to PHMSA according to § 192.18 with sufficient detail as listed in § 192.1007(c)(3)(ii)(A)–(F).

Because the statute requires operators to make an affirmative determination that there are no potential consequences associated with low probability events and recognizing that some operators might not have fully considered the risk of low-probability events based solely on operational knowledge, PHMSA proposes that any operational knowledge relied upon must include with it a quantifiable assessment and support the operator's determination with a level of rigor equal to that of an engineering analysis. This operational knowledge could be included as part of the proposed regulatorily required ''engineering analysis, or an equivalent analysis,'' as used in § 192.1007(c)(3)(ii). For example, should an operator determine that a release of gas from the pipeline, such as a leak, has no potential consequences, the operator should include documentation demonstrating that many scenarios were considered (such as a leak with ignition or gas migration under nearby pavement) and that no potential consequences were identified in any of those potential scenarios. This amendment would ensure that operators do not dismiss material risks without a meaningful evidentiary basis, and PHMSA or pertinent State authorities would have the opportunity to review and consider the validity of the operator's determination when reviewing DIMP plans.

State regulatory authorities already review operators' DIMP plans during regular inspections. Because incorrectly determining that a potential threat has no consequences would have serious public safety impacts, however, PHMSA understands there is a compelling policy reason for an operator's determination that a low-frequency event entails zero risk be reviewed by those State regulatory authorities as well as PHMSA. Therefore, if operators choose to apply the proposed exception in § 192.1007(c)(3)(ii), they must notify PHMSA and the appropriate State Authority in accordance with § 192.18 within 30 days of making this determination that there are no potential consequences associated with the low-probability event. The notification must include information such as the date the determination was made (to ensure compliance with the proposed timeline), descriptions of the low-probability events being considered, and a description of the logic supporting the determination, including information from an engineering analysis or an equivalent analysis incorporating operational knowledge. Further, this notification should contain a description of any preventive and mitigative measures, including any measures considered but not taken, as determined through the engineering analysis or an equivalent analysis incorporating operational knowledge. The notification should also include a description of the low-pressure system, including, at a minimum, miles of pipe, number of customers, number of district regulators supplying the system, and other relevant information. In addition, operators must provide a written statement summarizing the documentation it evaluated and how the conclusion that there would be no potential consequences associated with the low-probability event was reached. This documentation could include the inspection and maintenance history of the pipeline segment, incident reports, any leak repair data, and any failure investigations or abnormal operations records. Providing this information would be critical in ensuring that operators robustly evaluated methods of reducing risk and that the operator did not ignore any material factors in their engineering analysis or an equivalent analysis incorporating operational knowledge.

In a new § 192.1007(c)(3)(iii), PHMSA proposes to require that in evaluating and ranking risks in their DIMP plans, operators of low-pressure gas distribution systems must evaluate the configuration of their primary and any secondary overpressure protection installed at the district regulator stations, the availability of gas pressure monitoring at or near overpressure protection equipment, and the likelihood of any single event that immediately or over time could result in an overpressurization of the low-pressure system (see amended § 192.195(c)). Operators' overpressure protection configurations vary—some include a combination of relief valves, monitoring regulators, or automatic shutoff valves. Other operators have real-time monitoring devices located at the district regulator station, while yet others rely on telemetering devices. Some operators, as demonstrated by the events of September 13, 2018, may have an overpressure protection configuration that can be defeated by a single event, such as excavation damage, natural forces, an equipment failure, or incorrect operations. This amendment would ensure that operators are evaluating their existing overpressure protection system for inadequacies or additional risks that could result in an overpressurization of the system.

6. DIMP—Identify and Implement Measures To Address Risks (Section 192.1007(d))

a. Current Requirements—DIMP—Identify and Implement Measures To Address Risks

Section 192.1007(d) requires operators to determine and implement measures designed to reduce the risks from failure of their gas distribution pipeline systems following the identification of threats (in accordance with § 192.1007(b)) and the evaluation and ranking of risks (in accordance with § 192.1007(c)). Section 192.1007(d) also requires that these risk mitigation measures include an effective leak management program (unless all leaks are repaired when found). Although the specific process is not defined in § 192.1007(d), PHMSA has issued guidance material to support the implementation of these requirements.

In the guidance material, PHMSA states that operators should have a documented list of measures to reduce risks identified on their pipeline system.[87] The process for identifying risk mitigation measures must be based on identified threats to each pipeline segment and the risk analysis. Operators should rank pipeline segments and group segments that represent the highest risk as the most important candidates for which measures are taken to reduce risk. The operator should ensure that the highest priority measures for reducing risk are for the highest-ranked segments as indicated by the risk analysis. Because the design and operation of gas distribution systems are so diverse, no single risk control method is appropriate in all cases. Therefore, the objective of § 192.1007(d) is to ensure that each operator has documented and described existing and proposed measures to address the unique risks to its system and that the operator has evaluated and prioritized actions to reduce risks to pipeline integrity.

b. Need for Change—DIMP—Identify and Implement Measures To Address Risks

Proper implementation of a DIMP plan should result in aggressive oversight and replacement of higher-risk infrastructure. For example, there are many benefits to replacing old, cast-iron, low-pressure distribution pipes with newer materials, such as modern plastic pipe. Replacement projects, however, entail their own risks to public safety and the environment that need to be balanced against the risks associated with leaving a pipeline segment undisturbed. Poorly managed construction projects can result in property damage and personal injury, and replacement activity can include blowdowns to the atmosphere of methane gas that contribute to climate change. Work on existing pipeline facilities can also cause a catastrophic overpressurization, as was the case in CMA's 2018 incident. Operators must manage those risks while still implementing preventive and mitigative measures that would reduce the risk of identified threats.

In 2020, PHMSA issued an advisory bulletin to remind operators of the possibility of failure due to an overpressurization on low-pressure distribution systems.[88] In that advisory bulletin, PHMSA reminded operators of the existing DIMP regulations and recommended that per § 192.1007(d), operators take additional actions to reduce risks if they found their current overpressure protection design to be insufficient. PHMSA also identified for operators that ''[t]here are several ways that operators can protect low-pressure distribution systems from overpressure events,'' such as:

1. Installing a full-capacity relief valve downstream of the low-pressure regulator station, including in applications where there is only worker-monitor pressure control;
2. Installing a ''slam shut'' device;
3. Using telemetered pressure recordings at district regulator stations to signal failures immediately to operators at control centers; and
4. Completely and accurately documenting the location for all control (*i.e.,* sensing) lines on the system.

As discussed earlier, subsequent to the 2018 Merrimack Valley incident, PHMSA was required by statute to ensure that operators of low-pressure gas distribution systems evaluate the risk of overpressurization in their DIMP plans. (49 U.S.C. 60109(e)(7)(A)(ii)). For existing low-pressure systems, operators already have a mechanism in place—their DIMP—to evaluate their systems to ensure they can identify and implement measures to minimize the risk imposed by any inadequate overpressure protection.

c. PHMSA's Proposal To Amend § 192.1007(d)—DIMP—Identify and Implement Measures To Address Risks

PHMSA proposes to amend § 192.1007(d) to establish additional criteria for operators to evaluate when identifying and implementing measures to address risks identified in DIMP plans. PHMSA's proposal would require operators—when identifying and implementing measures—to specifically account for risks associated with the age of the pipe, the age of the system, the presence of pipes with known issues, and overpressurization of low-pressure distribution systems. PHMSA is adding these specific risks to § 192.1007(d) because they were the subject of recent incidents, as discussed earlier. This amendment would ensure that operators are not only identifying these specific threats (in § 192.1007(b)), but also implementing measures to address those risks. In a new § 192.1007(d)(2), PHMSA is proposing to explicitly require operators of existing low-pressure systems to take certain actions to prevent and mitigate the risk of an overpressurization that could be the result of any single event or failure. These actions include identifying, maintaining, and (if necessary) obtaining traceable, verifiable, and complete records that document the characteristics of the pipeline that are critical to ensuring proper pressure controls for the system. PHMSA discusses the criteria for these pressure control records in section IV.F of this NPRM.

In addition to this recordkeeping requirement, in a new § 192.1007(d)(2), PHMSA proposes that operators must confirm and document that each district regulator station meets the design standards in § 192.195(c)(1)–(3) or take the following actions: (1) identify preventative and mitigative measures based on the unique characteristics of their system to minimize the risk of overpressurization on low-pressure systems, or (2) upgrade their systems to meet design standards in § 192.195(c)(1)–(3). PHMSA discusses the criteria for this proposed upgrade in section IV.H of this NPRM. Should an operator choose to identify preventative and mitigative measures based on the unique characteristics of their system to minimize the risk of overpressurization, PHMSA proposes that the operator notify PHMSA and State or local pipeline authorities no later than 90 days in advance of implementing any alternative measures. PHMSA proposes that an operator must make this notification in accordance with § 192.18, which would include a description of the operator's proposed alternative measures, identification, and location of facilities to which the measures would be applied, and a description of how the measures would

[87] DIMP Guidance at 28.

[88] *See* ''Pipeline Safety: Overpressure Protection on Low-Pressure Natural Gas Distribution Systems,'' ADB–2020–02, 85 FR 61097 (Sept. 29, 2020).

ensure the safety of the public, affected facilities, and environment. This notification would ensure that operators are keeping PHMSA and State authorities informed of alternative measures to address risk. This amendment would apply to existing low-pressure systems that have evaluated and identified inadequate overpressure protections in accordance with § 192.1007(c).

PHMSA has also proposed to amend § 192.18 to reflect this proposed change by including a reference to § 192.1007. Should an operator choose to implement an alternative method of minimizing overpressurization, PHMSA proposes that the operator notify PHMSA and State or local pipeline authorities no later than 90 days in advance of implementing any alternative measures. PHMSA proposes that operators must make this notification in accordance with § 192.18, which would include a description of the operators' proposed alternative measures, identification, and location of facilities to which the measures would be applied, and a description of how the measures would ensure the safety of the public, affected facilities, and environment. This notification would ensure that operators are keeping PHMSA and State authorities informed of alternative measures to address risk.

PHMSA proposes these amendments pursuant to 49 U.S.C. 60102(t) and 60109(e)(7). The proposed amendments would reinforce the recommended actions from PHMSA's 2020 advisory bulletin in which PHMSA identified for operators of low-pressure distribution systems the risks inherent to those systems and the preventative or mitigative measures they should implement to address the risk of overpressurization. PHMSA expects that operators may already be complying with many of these practices subsequent to issuance of the advisory bulletin, which set forth PHMSA's existing policy and interpretation of the current DIMP requirements. In this NPRM, PHMSA proposes to codify this existing policy and interpretation in its regulations.

This amendment is also aligned with the NTSB's clarification to recommendation P–19–14 that PHMSA would not have to require that existing low-pressure gas distribution systems be completely redesigned; rather, PHMSA may satisfy the recommendation by requiring operators to add additional protections, such as slam-shut or relief valves, to existing district regulator stations or other appropriate locations in the system.[89]

7. DIMP—Small LPG Operators (Section 192.1015)

a. Current Requirements—DIMP and Annual Reporting for Small LPG Operators

A ''small LPG operator'' is currently defined at § 192.1001 as an operator of a liquefied petroleum gas (LPG) distribution pipeline system that serves fewer than 100 customers from a single source. Small LPG operators are treated differently in the DIMP regulations than larger operators and they follow their own set of DIMP requirements in § 192.1015 that reflect the relative simplicity of these pipeline systems. The current DIMP requirements for small LPG operators in § 192.1015 are less extensive than for other gas distribution systems, but still provide operator personnel direction for implementing their DIMP plans. Currently, under § 191.11, operators of small LPG systems are not required to submit an annual report to PHMSA.

b. Need for Change—DIMP—Applicability for Small LPG Operators

In the 2009 DIMP Final Rule, PHMSA imposed requirements for small LPG operators similar to those for other operators but with more limited requirements for documentation, consistent with how these operators are treated throughout the pipeline safety regulations. PHMSA did not require operators to report performance measures as they do not file annual reports. Although the DIMP requirements for small LPG operators are similar to those applicable to other operators, PHMSA codified them separately under § 192.1015, emphasizing that DIMPs for small LPG operators should reflect the relative simplicity of their pipeline systems.

On January 11, 2021, PHMSA issued a final rule titled ''Pipeline Safety: Gas Pipeline Regulatory Reform,''[90] which among other things, excepted master meters from the DIMP requirements. During the development of that rule, PHMSA received several comments in support of extending that exception to small LPG operators. For example, the National Association of Pipeline Safety Representatives (NAPSR) suggested that small gas distribution utilities with 100 or fewer customers—including small LPG operators—should be excepted from the DIMP requirements, stating that many master meter systems, small distribution systems, and small LPG systems typically have no threats beyond the minimum threats listed in § 192.1015(b)(2). Various other commenters, including the National Propane Gas Association (NPGA), AmeriGas, and Superior Plus Propane, voiced support for excepting small LPG operators from the DIMP requirements. The Pipeline Safety Trust did not oppose an exception from DIMP requirements for master meter systems in that rulemaking, only urging PHMSA and its State partners to ensure that master meter operators are managing the integrity risks to their systems outside the context of a DIMP plan. In response, PHMSA in the Gas Regulatory Reform Final Rule stated, ''that the decision about whether to extend the DIMP exception to [other] facilities or to all distribution systems with fewer than 100 customers would benefit from additional safety analysis and notice and comment procedures prior to further consideration.'' PHMSA went on to say that it would ''continue to evaluate the issue of DIMP requirements for small LPG systems and, if appropriate, propose changes in a future rulemaking[.]''[91]

On December 17, 2021, the NPGA filed a petition for rulemaking in accordance with 49 CFR 190.331.[92] NPGA petitioned PHMSA to amend 49 CFR part 192, subpart P to create an exception for small LPG systems in the DIMP requirements. In support of their petition, they cited that NPGA, PHMSA, and the National Academies of Sciences (NAS) have considered the operation and safety of small LPG systems for more than 10 years.[93] As an alternative, NPGA proposed that PHMSA could enable a special permit (through § 190.341) for small LPG systems, for which NPGA would assist small LPG system operators in providing necessary information to PHMSA in the special permit process.

[89] NTSB clarified this in an official correspondence to PHMSA on July 31, 2020. NTSB, ''Safety Recommendation P–19–014'' (July 31, 2020), *https://data.ntsb.gov/carol-main-public/sr-details/P-19-014.*

[90] 86 FR 2210 (Jan. 11, 2021) (''Gas Regulatory Reform Final Rule''). The comments submitted by stakeholders in this rulemaking may be found in Doc. No. PHMSA–2018–0046.

[91] 86 FR at 2216.

[92] NPGA, Petition for Rulemaking: Small Liquefied Petroleum Distribution Systems, Doc. No. PHMSA–2022–0102–001 (Dec. 17, 2021) (''NPGA Petition'').

[93] NPGA referenced the examples of: (1) PHMSA Gas Regulatory Reform Final Rule, 86 FR 2210; (2) Nat'l Academies of Sciences, Eng'g, and Med., ''Safety Regulation for Small LPG Distribution Systems'' (2018), *https://nap.edu/25245* (''NAS Study''); and (3) NPGA, Comment Re: Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines, Doc. No. PHMSA–RSPA–2004–19854–0197 (Oct. 23, 2008).

The basis of NPGA's petition is that small LPG system operators are comparable to master meter systems, a set of operators that PHMSA recently removed from the DIMP requirements through the 2021 Gas Regulatory Reform Final Rule. As NPGA explained, master meter systems tend to be operated by small entities with simple systems compared to natural gas distribution operators. Master meters also often include only one type of pipe, and the systems operate at a single operating pressure. Similarly, as NPGA stated, the vast majority of small LPG pipeline systems are single property systems that occupy a small, overall footprint in size and generally operate at a single operating pressure. Although such systems may be metered or non-metered, the nature of their simplicity in size and application make them comparable to master meter systems such that, owing to their ''nearly identical'' function and structure, ''the two systems should be categorized together for the same treatment under the regulations'' exempting them from DIMP requirements.[94]

NPGA reiterated that PHMSA further noted in the 2021 Gas Regulatory Reform Final Rule that the agency's experience indicated the analysis and documentation requirements of DIMP had little safety benefit for this type of operator and that focusing on more fundamental risk mitigation activities has more safety benefits than implementing a DIMP for this class of operators. NPGA went on to reiterate PHMSA's position in the Gas Regulatory Reform Final Rule (as discussed above), where PHMSA indicated that exempting master meter operators from subpart P would result in cost savings for master meter operators without negatively impacting safety. NPGA stated that PHMSA had previously expressed its intention to address small LPG systems in a future rulemaking and added that this change would not conflict with the Administration's aims of reducing methane emissions.[95]

PHMSA has reviewed and considered NPGA's petition and agrees with its assertion that small LPG systems do not present the same complexity or incur the same risks as large networks of pipeline systems crossing hundreds of miles. Therefore, PHMSA addresses NPGA's petition through this proposed rule and continued oversight through partnership with State agencies.

PHMSA has concluded that its existing approach requiring small LPG operators to comply with limited DIMP requirements offers little public safety benefit. Small LPG operators by definition have limited systems serving a small number of customers; in fact, NAPSR data suggests that there are only between 3,800 and 5,800 multi-user systems nationwide, with most serving fewer than 50 customers (often well below 50 customers).[96] Small LPG systems are also more simple systems—less piping and fewer components that could fail—that are inherently less susceptible to loss of pipeline integrity than large gas distribution systems. Further, PHMSA incident data indicate that small LPG systems entail relatively low public safety risks. PHMSA's incident data suggest small LPG systems average less than one incident involving a fatality or serious injury per year. Incidents reported by operators to PHMSA from 2010 through 2017 include 10 incidents, seven injuries, and approximately $2 million in property damage.[97] No fatalities have been reported since 2006. Incorporating fire events from the National Fire Incident Reporting System with the PHMSA incident data suggests that the number of incidents involving LPG distribution systems averages in the single digits per year. And, because releases of LPG are not themselves generally considered GHG emissions, continued regulation of small LPG systems pursuant to PHMSA's DIMP requirements provides little benefit for mitigating climate change.

PHMSA understands that even limited DIMP requirements can place a significant compliance burden on small LPG operators and administrative burdens on PHMSA and State regulatory authorities—which in turn can detract from other safety efforts. A 2018 study issued by the NAS found that there is significant regulatory uncertainty among small LPG operators regarding whether PHMSA's DIMP regulations apply at all—resulting in many such operators neither understanding they are obliged to comply with PHMSA regulations nor being regularly inspected by State regulatory authorities.[98]

Given their small size and the relative simplicity of their systems, as discussed in the preceding paragraphs, and the significant compliance burden that DIMP requirements impose on such entities with limited safety benefit, PHMSA has determined that it is more appropriate to exempt small LPG operators from DIMP requirements but impose an annual reporting requirement on these operators.

c. PHMSA's Proposal To Exempt Small LPG Operators From DIMP Requirements and Extend Annual Reporting Requirements to Small LPG Systems

PHMSA proposes to add a new § 192.1003(b)(4) and delete existing § 192.1015 to remove small LPG operators from DIMP requirements but extend annual reporting requirements to these operators. With small LPG operators removed from DIMP requirements at § 192.1015, the definition of small LPG operators in § 192.1001 becomes redundant and therefore PHMSA would also remove it from DIMP. In developing this proposal, PHMSA considered the comments made in the Gas Regulatory Reform Final Rule on the topic of the application of DIMP requirements to small LPG operators, the NPGA's petition for rulemaking, the NAS study, and PHMSA's incident data. PHMSA has preliminarily determined that continuing to impose DIMP requirements (even in the abbreviated form pursuant to existing § 192.1015) on small LPG systems that have been proven by PHMSA incident data to entail inherently limited public safety risks imposes outsized compliance burdens on operators and administrative burdens on PHMSA and State regulatory authorities.[99] At the same time, extending the annual reporting requirement to these operators is intended to ensure that PHMSA will maintain the ability to identify and respond to systemic or emerging issues on those systems.

PHMSA does not expect that this proposed exception from DIMP requirements would adversely impact public safety. As discussed above, PHMSA understands the public safety benefits attributable to existing, limited DIMP requirements for small LPG operators are limited. PHMSA will be able to retain regulatory oversight of small LPG operator systems through

[94] NPGA Petition at 3.

[95] NPGA Petition at 3–5. PHMSA notes that LPG releases are not themselves generally considered to be releases of GHGs.

[96] NAS Study at 83.

[97] NAS Study at 41, Table 3–4.

[98] The NAS Study identified as a source of much of that regulatory uncertainty the varied interpretations of ''public place'' used at § 192.1(b)(5) to determine if certain petroleum gas systems are subject to PHMSA's 49 CFR part 192 regulations. NAS Study at 87–88.

[99] Nor does PHMSA expect that small LPG operators would experience improvements in pipeline safety from the regulatory amendments that PHMSA is proposing in this NPRM for other (larger) gas distribution operators. For example, PHMSA's incident data from 2010 through 2021 shows 12 incidents involving propane gas. In reviewing those incidents, PHMSA found that the age, material type, and operations of low-pressure distribution systems were not relevant to small LPG operators serving fewer than 100 customers; nor did those incidents involved an exceedance of MAOP.

other requirements within 49 CFR part 192, including the proposed annual reporting requirement and the incident reporting requirements at 49 CFR part 191.

To improve the information available to PHMSA and State regulatory authorities for identifying and addressing systemic public safety issues from small LPG systems, PHMSA is proposing to revise § 191.11 to require operators of small LPG systems to submit annual reports using newly designated form PHMSA F 7100.1–2. These annual reports would require operators of small LPG systems to report the location and number of customers served by their distribution pipeline systems, as well as the disposition of any discovered leaks. PHMSA expects that through an annual reporting requirement, PHMSA would also be able to provide better data to the public on small LPG systems, which the agency could assess and may ultimately inform a future rulemaking. PHMSA also expects that its proposal to require annual reporting for small LPG operators may help alleviate the confusion noted by the NAS Study regarding whether those operators are subject to PHMSA regulations at 49 CFR part 192.

PHMSA expects the extension of its part 191 annual reporting requirements to small LPG systems would be reasonable, technically feasible, cost-effective, and practicable. The information PHMSA collects on its current annual report form for gas distribution operators (Form F7100.1–1) does not require significant technical expertise or particularly expensive equipment to populate; small LPG operators may also reduce their burdens further by contracting with vendors to operate and perform maintenance on their systems and complete annual report forms. PHMSA also expects that the forthcoming annual report form (PHMSA F 7100.1–2) specific to small LPG operators will be a further simplified version of the current annual report form. Additionally, PHMSA notes that the information it expects will be collected within that simplified annual report form—operator corporate information, length and composition of the system, leaks on that system, etc.—is minimal information that a reasonably prudent small LPG operator would maintain in ordinary course given that their systems transport pressurized (natural, flammable, toxic, or corrosive) gasses. Viewed against those considerations and the compliance costs estimated in section V.D herein and the PRIA, PHMSA expects the new annual reporting requirement for these operators will be a cost-effective approach to ensuring PHMSA has adequate information to monitor the public safety and environmental risks associated with small LPG systems that would no longer be subject to DIMP requirements. Lastly, PHMSA expects that the compliance timeline proposed for this new reporting requirement—which would begin with the first annual reporting cycle after the effective date of any final rule issued in this proceeding (which would necessarily be in addition to the time since publication of this NPRM)—would provide affected operators ample time to compile requisite information and familiarize themselves with the new annual report form (and manage any related compliance costs).

B. State Pipeline Safety Programs (Sections 198.3 and 198.13)

1. Current Requirements—State Programs and Use of SICT

PHMSA relies heavily on its State partners for inspecting and enforcing the pipeline safety regulations. The pipeline safety regulations provide that States may assume safety authority over intrastate pipeline facilities, including gas pipeline, hazardous liquid pipeline, and underground natural gas storage facilities through certifications and agreements with PHMSA under 49 U.S.C. 60105 and 60106. States may also act as an interstate agent on behalf of DOT to inspect interstate pipeline facilities for compliance with the pipeline safety regulations pursuant to agreement with PHMSA.

To support states' pipeline safety programs, PHMSA provides grants to reimburse up to 80 percent of the total cost of the personnel, equipment, and activities reasonably required by the State agency to conduct its safety programs during a given calendar year. 49 CFR part 198 contains regulations governing grants to aid State pipeline safety programs. PHMSA also maintains ''Guidelines for States Participating in the Pipeline Safety Program'' (''Guidelines''), which contains guidance for how State pipeline safety programs should conduct and execute their delegated responsibilities.[100] The Guidelines promote consistency among the many State agencies that participate under certifications and agreements and are updated on an annual basis.

In 2017, PHMSA adopted within its Guidelines the State Inspection Calculation Tool (SICT), a tool that helps states conduct an inspection activity needs analysis for regulatory oversight of every operator subject to its jurisdiction, for the purpose of establishing a base level of inspection person-days[101] needed to maintain an adequate pipeline safety program.[102] In the SICT, each State agency considers the type of inspection it needs to conduct (*e.g.,* standard, comprehensive, integrity management, operator qualification, damage prevent activities, drug and alcohol); analyzes each operator's system for several risk factors (*e.g.,* cast iron pipe, replacement construction activity, compliance issues); assigns each operator a risk ranking based on the risk factors (*e.g.,* leak prone pipe would have a higher score than modern, coated, and cathodically protected pipe); and lists other unique concerns and considerations (*e.g.,* travel distance to conduct the inspection) applicable to each operator.[103] Each State agency proposes an inspection activity level for each operator, which is subsequently peer-reviewed before being finalized by PHMSA. PHMSA expects that each State agency will dedicate a minimum of 85 inspection person-days for each of its full-time pipeline safety inspectors for pipeline safety compliance activities each calendar year.[104] PHMSA considers a State agency's inspection activity level, among several other factors, when awarding grants to State pipeline safety programs.

2. Need for Change—State Programs and Use of the SICT

A State is authorized to enforce safety standards for intrastate pipeline facility or intrastate pipeline transportation if the State submits annually to PHMSA a certification that complies with 49 U.S.C. 60105(b) and (c). As amended in 2020, the certification includes a requirement that each State agency have the capability to sufficiently review and evaluate the adequacy of each distribution system operator's DIMP plan, emergency response plan, and operations, maintenance, and emergency procedures, as well as ''a

[100] PHMSA, ''Guidelines for States Participating in the Pipeline Safety Program'' (Jan. 2022), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2020-07/2020-State-Guidelines-Revision-with-Appendices-2020-5-27.pdf.*

[101] PHMSA proposes below that an inspection person-day means ''all or part of a day, including travel, spent by State agency personnel in on-site or virtual evaluation of a pipeline system to determine compliance with Federal or State Pipeline Safety Regulations.''

[102] The SICT is located on PHMSA's access restricted database portal.

[103] Instructions for how to use the SICT and inspection activity needs analysis examples are in the Guidelines.

[104] This 85-day requirement is not tied to each individual inspector. It is an 85-day average over all inspectors.

sufficient number of employees'' to help ensure the safe operations of pipeline facilities, as determined by the SICT. (49 U.S.C. 60105(b)). PHMSA updates Guidelines and its evaluation process annually to ensure that State agencies are meeting the certification requirements.[105]

In certifying that the State has a ''sufficient number of employees'', the State must use the SICT to account for:

1. The number of miles of gas and hazardous liquid pipelines in the State, including the number of miles of cast iron and bare steel pipelines;
2. The number of services in the State;
3. The age of the gas distribution systems in the State; and
4. Environmental factors that could impact the integrity of the pipeline, including relevant geological issues.

Currently, the SICT accounts for the size (*e.g.,* mileage, service line count, etc.) of each operator's system; type of operator and product being transported; risk factors of material composition, including but not limited to, the presence of cast iron and bare steel; and environmental factors that could impact the integrity of a pipeline, including geological issues. Total miles of gas and hazardous liquid pipelines in a State and the age of gas distribution systems are, however, only implicitly considered. To comply with the mandate, PHMSA proposes to codify within its regulations the use of the SICT for establishing inspection person-days and update the SICT to explicitly include the total gas or hazardous liquid pipeline mileage in the State and the age of a gas distribution system as a factor for consideration.

3. PHMSA's Proposal To Codify the Use of the SICT in Pipeline Safety Regulations

This NPRM proposes amendments to the pipeline safety regulations at 49 CFR part 198 to codify use of the SICT by all PHMSA's State partners holding certifications or agreements per 49 U.S.C. 60105 or 60106. Specifically, PHMSA proposes to revise § 198.3 to add definitions for ''inspection person-day'' and ''State Inspection Calculation Tool'' and by revising § 198.13 to include the use of the SICT for determining inspection person-days. PHMSA proposes to define ''inspection person-day'' to mean ''all or part of a day, including travel, spent by State agency personnel in on-site or virtual evaluation of a pipeline system to determine compliance with Federal or State Pipeline Safety Regulations.'' PHMSA will continue to permit travel to be included for inspection person-days even if travel requires a full day before or after the inspection because some states cover a large geographical area that requires substantial travel time and a State agency's staffing requirement could be impacted if travel is not considered. PHMSA will also continue to allow inspection person-days to be counted for those individuals who have not completed training requirements but who assist in inspections if they are supervised by a qualified inspector. PHMSA proposes to define the term ''State Inspection Calculation Tool (SICT)'' to mean ''a tool used to determine the required minimum number of annual inspection person-days for a State agency.'' These proposed definitions are consistent with those in the Guidelines.

PHMSA is required to promulgate regulations to require that a State authority with a certification under 49 U.S.C. 60105 has a sufficient number of qualified inspectors to ensure safe operations, as determined by the SICT and other factors determined appropriate by the Secretary. (49 U.S.C. 60105 note). Pursuant to this legal requirement, PHMSA proposes revising § 198.13(c)(6) to state that when allocating funding and considering various performance factors, PHMSA considers the number of State inspection person-days, ''as determined by the SICT and other factors.'' These amendments would codify PHMSA's current practice of using the SICT in the determination of the minimum number of inspection person-days each State must dedicate to inspections in a given calendar year.

C. Emergency Response Plans (Section 192.615)

The pipeline safety regulations require operators to have written procedures for responding to emergencies involving their pipeline systems to ensure a coordinated response to a pipeline emergency. This response includes communicating with fire, police, and other public officials promptly. Through a final rule issued on April 8, 2022, titled ''Requirement of Valve Installation and Minimum Rupture Detection Standards'', PHMSA extended that emergency communication for all gas pipeline operators to include a public safety answering point (PSAP; *i.e.,* 9–1–1 emergency call center).[106] Among other changes, the Valve Rule amended § 192.615(a) to ensure proper communication with PSAPs, requiring operators to immediately and directly notify PSAPs upon notification of a potential rupture. However, the Valve Rule requirements were not in effect at the time of the Merrimack Valley incident.

Subsequent to the 2018 Merrimack Valley incident, 49 U.S.C. 60102 was amended to improve the emergency response and communications of gas distribution operators during gas pipeline emergencies in several ways. Specifically, 49 U.S.C. 60102(r) was added, which requires PHMSA to promulgate regulations ensuring that gas distribution operators develop written emergency response procedures for notifying and communicating with emergency response officials as soon as practicable from the time of confirmed discovery of certain gas pipeline emergencies; communicate with the public during and after such a gas pipeline emergency; and establish an opt-in system for operators to rapidly communicate with customers. Gas distribution operators must make their updated emergency response plans available to PHMSA or the relevant State regulatory agency within 2 years after the final rule is issued, and every 5 years thereafter (49 U.S.C. 60108(a)(3)).

PHMSA, in this NPRM, proposes building on the Valve Rule's changes to emergency response plan requirements through additional changes to ensure prompt and effective emergency response coordination. For all gas pipeline operators subject to § 192.615,[107] PHMSA proposes to expand the requirements to have procedures for a prompt and effective response to include emergencies involving notification of potential ruptures, a release of gas that results in a fatality, and any other emergencies deemed significant by the operator, with similar requirements to notify PSAPs in those instances. PHMSA understands these proposed amendments of existing emergency response plan requirements as applicable to all part 192-regulated pipelines would be reasonable, technically feasible, cost-effective, and practicable. The proposed changes are common-sense, incremental supplementation of current requirements regarding the content and execution of emergency response plans for gas pipeline operators.

[105] PHMSA anticipates issuing updated Guidance to reflect the changes to the Pipeline Safety Grant Program.

[106] 87 FR at 20940, 20973.

[107] PHMSA notes that § 192.9(d) does not currently require compliance with § 192.615 for Type B gathering lines, however PHMSA has proposed, in another rulemaking, to amend § 192.9(d) to require Type B gas gathering operators to comply with § 192.615. *See* 88 FR at 31952–53, 31955–56.

Implementation of the proposed requirements should not require special expertise or investment in expensive new equipment; PHMSA expects that some operators may already comply with these proposed requirements either voluntarily or due to similar requirements imposed by State pipeline safety regulators. And insofar as these incremental proposed additions to emergency planning requirements are consistent with historical PHMSA guidance, industry operational experience, and the lessons learned from incidents such as the Merrimack Valley incident, they are precisely the sort of actions a reasonably prudent operator of any gas pipeline facility would maintain in ordinary course given that their systems transport commercially valuable, pressurized (natural flammable, toxic, or corrosive) gasses. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments are a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their procedures (and manage any related compliance costs).

PHMSA proposes additional requirements for gas distribution operators. First, those operators would be subject to an expanded list of emergencies that includes unintentional releases of gas with significant associated shutdown of customer services. Second, gas distribution operators must establish written procedures for communications with the general public during an emergency, and continue communications through service restoration and recovery efforts, to inform the public of the emergency and service restoration and recovery efforts. Third, gas distribution operators would be required to develop and implement for their customers an opt-in or opt-out notification system to provide them with direct communications during a gas pipeline emergency. PHMSA understands its proposed amendments enhancing existing emergency response plan requirements would be reasonable, technically feasible, cost-effective, and practicable for affected gas distribution operators. PHMSA expects that some gas distribution operators may already comply with these requirements either voluntarily or due to similar requirements imposed by State pipeline safety regulators. PHMSA also expects that operators will already have (due to the need to bill their customers) the requisite contact information needed to implement voluntary opt-in or opt-out notification systems; as explained below, some operators may also be able to leverage existing emergency notification systems maintained by local and State government officials in satisfying this proposed requirement. PHMSA further notes that its proposed enhancements for emergency communications are precisely the sort of minimal actions a reasonably prudent operator of gas distribution pipeline facility would undertake in ordinary course to protect each of (1) the public safety, given that their systems transport pressurized (natural, flammable, toxic, or corrosive) gasses; and (2) their customers, given the economic cost to those customers from interruption of supply. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the public safety and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—between 12 to 18 months after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their procedures and procure necessary personnel and vendor services (and manage any related compliance costs).

Finally, PHMSA is requesting comments on whether it should require gas distribution operators to follow incident command systems (ICS) during an emergency response. PHMSA may consider whether to include this requirement in any final rule in this proceeding. The sections below discuss each of these proposals in more detail.

1. Emergency Response Plans—First Responders

a. Current Requirements—Emergency Response Plans—Notifying PSAPs, First Responders, and Public Officials

Section 192.615(a) requires that each gas pipeline operator have written procedures for responding to gas pipeline emergencies, including for how operators are expected to communicate with fire, police, and other appropriate public officials before and during an emergency. The Valve Rule revised § 192.615(a)(2) to add direct communication with PSAPs in response to gas pipeline emergencies and required operators to establish and maintain an adequate means of communication with PSAPs.[108] Further, the Valve Rule revised § 192.615(a)(8) to require operators to notify these entities and coordinate with them during an emergency. This communication to the appropriate PSAPs must occur immediately and directly upon receiving a notification of potential rupture to coordinate and share information to determine the location of any release.[109] The Valve Rule also revised § 192.615(c) to require each operator establish and maintain liaison with the appropriate PSAPs ''where direct access to a 9–1–1 emergency call center is available from the location of the pipeline, as well as fire, police, and other public officials'' to coordinate responses and preparedness planning.

Further, PHMSA issued an advisory bulletin in 2012 (ADB–2012–09) regarding communications between pipeline operators and PSAPs.[110] In the advisory bulletin, PHMSA reminded operators that they should notify PSAPs of indications of a pipeline facility emergency, including an unexpected drop in pressure, an unanticipated loss of SCADA communications, or reports from field personnel. In the advisory bulletin, PHMSA recommended that pipeline operators immediately contact the PSAPs of the communities in which such indications occur. Furthermore, the advisory bulletin noted that operators should have the ability to immediately contact PSAPs along their pipeline routes if there is an indication of a pipeline emergency to determine if the PSAP has information that may help the operator confirm whether a pipeline emergency is occurring or to provide assistance and information to public safety personnel who may be responding to the event. The revisions to § 192.615 in the Valve Rule essentially codified this advisory.

[108] PHMSA expects that ''maintaining adequate means of communication'' should include, but not be limited to, considering the frequency of communication, changes to the nature of the emergency, changes to previously liaised information, and updates to other emergency response information, as determined by the operator.

[109] 87 FR at 20983.

[110] ''Pipeline Safety: Communication During Emergency Situations,'' ADB–2012–09, 77 FR 61826 (Oct. 11, 2012). PHMSA also issued draft FAQs on 9–1–1 notification on July 8, 2021. ''Frequently Asked Questions on 911 Notifications Following Possible Pipeline Ruptures,'' 86 FR 36179 (July 8, 2021). If PHMSA were to finalize the proposed revisions for these emergency plan provisions in a subsequent final rule, PHMSA would withdraw the draft 9–1–1 notification FAQs as redundant.

PHMSA notes that indications of a gas pipeline emergency, including unexpected pressure drops or reports from field personnel, might be a notification of potential rupture under amended § 192.615, which would require the direct and immediate notification of the appropriate PSAP.

b. Need for Change—Emergency Response Plans—Notifying PSAPs, First Responders, and Public Officials

During the initial response to the 2018 Merrimack Valley incident, the three fire departments in the affected municipalities were inundated with emergency calls from residents and businesses reporting fires and explosions and requesting assistance shortly after 4 p.m. on September 13, 2018. Around that same time, the CMA technician reported smoke and explosions. However, it was not until nearly 4 hours later at 7:43 p.m. that the president of CMA declared a ''Level 1'' emergency under CMA's emergency response plan. Lawrence's deputy fire chief told NTSB investigators that, during the incident response, he attempted to contact CMA through the station dispatch to get a status update to see if CMA had the gas incident under control but did not receive updates from the company until hours later. About 2 hours after the initial fires, Lawrence's deputy fire chief assumed the gas company had resolved the incident.[111] The Andover fire chief recognized the events occurring were gas-related and contacted CMA through a regular dispatch number to provide status updates so the fire department could relay information to the public. He told NTSB investigators that CMA did call him back more than 4 hours later, while also acknowledging the delay was likely caused by the number of emergency calls CMA received.

The NTSB report noted that CMA had emergency response plans but did not implement their plans in a manner that would allow them to effectively respond to such a large incident, explaining that ambiguities within the operator's emergency response plans could have contributed to the poor emergency response in that incident. Specifically, the NTSB pointed out that the operator's emergency response plans suggested that notification could be discretionary, as those procedures stated that when an overpressurization of the system occurs, there ''may be a need'' to communicate with local government officials and emergency management agencies, as well as with fire and police departments.[112] According to the NTSB report, the NiSource emergency plan also stated that it is ''imperative for all entities involved to remain informed of each other's activities,'' and that CMA's Incident Commander (IC), (in this case, the field operations leader (FOL)) was required to establish appropriate contacts for communication purposes throughout the incident. However, during the initial hours of the event, the IC did not establish these requisite communication contacts because the IC was involved with shutting down the natural gas system. And although CMA representatives went to emergency responder staging areas and emergency operations centers, the NTSB report noted that CMA representatives could not address many of the questions from emergency responders because the representatives were not prepared with thorough and actionable information. As a result of the lack of timely, thorough, and actionable information on the circumstances of the overpressurization event, emergency responders unnecessarily evacuated areas, straining limited emergency response resources, and creating confusion among the public. The NTSB concluded that CMA was not adequately prepared with the resources necessary to assist emergency management services with the emergency response.

Subsequent to the 2018 Merrimack Valley incident, PHMSA was required by law to promulgate regulations to ensure that gas distribution system operators include in their emergency response plans written procedures for notifying ''first responders and other relevant public officials as soon as practicable, beginning from the time of confirmed discovery, as determined by [PHMSA], by the operator of a gas pipeline emergency,'' and including gas distribution-specific indications of what constitutes a gas pipeline emergency. (49 U.S.C. 60102(r)).

c. Proposal To Amend § 192.615—Emergency Response Plans—Notifying PSAPs, First Responders, and Public Officials

As discussed earlier, the Valve Rule revised the existing emergency response regulations to require operators notify PSAPs in the event of gas pipeline emergencies, and immediately and directly notify PSAPs when receiving a notification of potential rupture. In this NPRM, PHMSA proposes to revise the non-exclusive list at § 192.615(a)(3) of gas pipeline emergencies requiring all part 192-regulated gas pipeline operators to undertake prompt, effective response on notification of potential ruptures; a release of gas that results in one or more fatalities; and any other emergency deemed significant by the operator. PHMSA is also proposing that gas distribution pipeline operators would need to undertake prompt, effective response on notification of the unintentional release of gas and shutdown of gas service to either 50 or more customers or, if the operator has fewer than 100 customers, 50 percent of total customers. Additionally, PHMSA proposes to amend existing requirements at § 192.615(a)(8) to apply its requirement for operators of all gas pipelines to establish written procedures for immediately and directly notifying PSAPs, or other coordinating agencies for the communities and jurisdictions in which the pipeline is located, to include after a notification of these gas pipeline emergencies. Gas distribution operators, moreover, would also have to immediately and directly notify PSAPs on notification of an unintentional release and shutdown of gas services where either 50 or more customers lose service, or for operators with fewer than 100 customers, if 50 percent of all the operator's customers lose service.

i. What is a ''Gas Pipeline Emergency?''

PHMSA is revising the list of gas pipeline emergencies in § 192.615(a)(3) to add: (1) for all part 192-regulated gas pipeline operators, events involving 1 or more fatalities or any other emergency deemed significant by the operator; and (2) for gas distribution pipeline operators only, an unintentional release of gas resulting in a shutdown of gas services affecting at least 50 customers, or for operators with fewer than 100 customers, 50 percent of customers.[113]

The statutory language does not elaborate on the meaning of ''significant'' within its usage in the phrase ''the unscheduled release of gas and shutdown of gas service to a significant number of customers.'' Therefore, PHMSA proposes to establish the threshold for a ''significant number of customers'' to be 50 customers or, for operators with fewer than 100 customers, 50 percent of all the operator's customers. In determining this threshold, PHMSA reviewed the

[111] NTSB, PLD18MR003, ''Interview of: Kevin Loughlin, Deputy Chief Lawrence Fire Department,'' (Sept. 15, 2018), *https://data.ntsb.gov/Docket/Document/docBLOB?ID=40476257&FileExtension=.PDF&FileName=Emergency%20Response%20-%20Interview%20of%20Lawrence%20Deputy%20Fire%20Chief-Master.PDF.*

[112] NTSB/PAR–19/02 at 46.

[113] PHMSA also is adding, applicable to all part 192-regulated gas pipeline operators, ''potential rupture'', consistent with the amendment in the Valve Rule to § 192.615(a)(8).

data for all reportable gas distribution incidents from 2010 to 2021 and averaged the number of residential, commercial, and industrial customers affected by those incidents.[114]

PHMSA also proposes to add ''other emergency deemed significant by the operator'' to the list of examples of a gas pipeline emergency to allow operators to use their best professional judgment when coordinating with first responders and other relevant public officials and account for other system-specific circumstances, such as an outage to a single customer that happens to be a hospital or other critical-use facility, when complying with § 192.615. This amendment would specify a non-exclusive list of gas pipeline emergencies.

ii. When must operators communicate with PSAPs, first responders, and other relevant public officials?

PHMSA proposes to adopt the aforementioned more-inclusive list of gas pipeline emergencies into the § 192.615(a)(8) notification requirements established in the Valve Rule that required the immediate and direct notification of PSAPs and other relevant emergency responders and public officials after receiving notice of such an emergency. Pursuant to 49 U.S.C. 60102(r), operator communications with first responders and other relevant public officials must occur ''as soon as practicable, beginning from the time of confirmed discovery, as determined by the Secretary, by the operator of a gas pipeline emergency.'' PHMSA, in §§ 191.5 and 195.52, already uses the term ''confirmed discovery'' [115] to require operators to report certain events to the National Response Center at the earliest practicable moment following ''confirmed discovery;'' however, these notifications may occur up to 1 hour after confirmation. Further, those §§ 191.5 and 195.52 reportable events may not always constitute a gas pipeline emergency as proposed in § 192.615. Because the 49 U.S.C. 60102(r) mandate directs PHMSA to improve and expand emergency response efforts—distinct from operator notification of incidents/accidents for reporting purposes—PHMSA determines that the timing of local emergency communication must come immediately and directly upon indication of such a gas pipeline emergency. PHMSA, therefore, does not propose to interpret ''confirmed discovery'' in 49 U.S.C. 60102(r) to apply in § 192.615(a) in the same manner as the term is used in 49 CFR parts 191 and 195.[116] Instead, PHMSA proposes ''confirmed discovery'' in 49 U.S.C. 60102(r), for purposes of § 192.615, to mean immediately after receiving notice of a gas pipeline emergency.[117] This will bring local emergency services to bear as near as possible to a gas pipeline emergency based on early indications, rather than considering whether the gas pipeline emergency is also a reportable event under § 191.5 before initiating an emergency response.

PHMSA proposes that gas pipeline emergencies be immediately and directly communicated to local emergency responders because any delays in emergency response may make the emergency significantly more difficult to contain. PHMSA expects that in no case should that ''immediate'' communication to PSAPs begin any later than 15 minutes following initial notification to the operator of that emergency. This expectation is consistent with certain criteria for ''notification of a potential rupture'' adopted in the Valve Rule,[118] and would ensure the timely and effective implementation of the pipeline operator's emergency response plan and coordinated response with local public safety officials. PHMSA also expects that if a gas pipeline emergency also meets the criteria of an incident in § 191.3, operators would report the incident to the National Response Center in accordance with § 191.5, as already required.

iii. What information should operators provide to first responders and public officials?

As the emergency response to the Merrimack Valley incident continued, public safety officials asked CMA for detailed information on the locations of the overpressurized gas lines to aid in assessing the scope and scale of the incident. Officials requested maps and lists of impacted customers and impacted streets, but CMA did not provide them in a timely manner. This significantly hampered the response to the event and caused first responders to take unnecessary actions during the immediate response efforts. For example, instead of targeting specific residents based on the location of the affected services, first responders needed to go door to door to evaluate safety impacts and determine where the gas lines were overpressurized. To prevent such delays from occurring in the future, PHMSA recommends operators provide first responders and public officials with pertinent information, as it becomes available, to support emergency communications during a gas pipeline emergency, including: (1) the operator's response efforts; (2) information on the gas service sites impacted by the release; (3) the magnitude of the incident and its expected impact; (4) the location(s) of the emergency and of affected customers; (5) the specific hazard and the potential risks; and (6) the operator point of contact responsible for addressing first responder and public official questions and concerns. Procedures to provide such information must be included in their emergency response plans and should also comport with guidance by the Federal Emergency Management Agency (FEMA) for State and local governments in developing effective hazard mitigation planning and would help ensure that appropriate instructions, directions, and information is provided to the right people at the appropriate time.[119]

2. Emergency Response Plans—General Public

a. Current Requirements—Emergency Response Plans—General Public

Currently, there are no Federal regulations requiring gas distribution operators to establish communications with the general public during or following a gas pipeline emergency. Section 192.615 requires operator

[114] *See* PHMSA, ''Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data'' (Aug. 31, 2022), *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.*

[115] The term ''confirmed discovery,'' defined at §§ 191.3 and 195.3, ''means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.''

[116] Relying on the same operative phrase (''confirmed discovery'') that is already used to notify the National Response Center of reportable incidents risks introducing confusion and uncertainty with respect to what regulations to follow and how to incorporate these regulations into response plans for when operators must contact local emergency responders. In an emergency, clarity is critical and PHMSA believes that utilizing distinct regulatory phrases for these different duties will help distinguish and clarify responsibilities in an emergency response.

[117] PHMSA's proposal anticipates that an operator will alert local emergency response officials upon earliest indications of gas pipeline emergencies.

[118] *See* § 192.635(a)(1) (specifying a 15-minute time interval for evaluating significant pressure losses on gas pipelines as an indicium of a rupture).

[119] FEMA, ''Lesson 3: Communicating in an Emergency'' (Feb. 2014), *https://training.fema.gov/emiweb/is/is242b/instructor%20guide/ig_03.pdf.*

coordination and communication with only fire, law enforcement, emergency management, and other public safety officials. Section 192.616 contains requirements for public awareness but does not contain provisions specific to communications with the public during or after an emergency.[120]

b. Need for Change—Emergency Response Plans—General Public

In any gas pipeline emergency, communicating basic information and a consistent message can be difficult. While communication with emergency responders is important, so too is contemporaneously updating affected members of the public, as both serve to reduce public safety harms. CMA's failure to communicate promptly with its affected customers throughout the 2018 Merrimack Valley incident showed deficiencies in CMA's incident response planning. CMA first provided the public with information regarding the incident at approximately 9:00 p.m. on September 13, 2018—nearly 5 hours after the onset of the emergency at approximately 4:00 p.m. when the first 9–1–1 calls on the incident were made. Although CMA was still gathering relevant information during the first several hours following the incident and did not have a complete understanding of the situation, it nevertheless should have conveyed information to the public on the nature of the incident and affected areas more quickly.

Subsequent to the 2018 Merrimack Valley incident, PHMSA was directed in 49 U.S.C. 60102(r) to revise its regulations to ensure that each gas distribution operator includes written procedures in its emergency plan for ''establishing general public communication through an appropriate channel'' as soon as practicable after a gas pipeline emergency. In particular, operators should communicate to the public information regarding the gas pipeline emergency and ''the status of public safety.''

c. PHMSA's Proposal To Amend § 192.615—Emergency Response Plans—General Public

Gas distribution pipeline operators are not currently required to communicate public safety or service interruption and restoration information to the public during and following a gas pipeline emergency. Therefore, PHMSA proposes that gas distribution operators include procedures for establishing and maintaining communication with the general public as soon as practicable during a gas pipeline emergency on a gas distribution pipeline. Operators would need to continue communications through service restoration and recovery efforts. Operators would need to establish communication through one or more channels appropriate for their communities, which could include in-person events (*e.g.,* press conferences or town hall-style events), print media, broadcast media, the internet or social media, text messages, phone apps, or any combination of these channels. Further, PHMSA proposes that such communications must include the following components:

1. Information regarding the gas pipeline emergency (which could include the specific hazard and potential risks to the community, the location of the incident and boundaries of the impacted area, the magnitude of the event and the expected impact, protective actions the public should take, and how long the public may be impacted),

2. The status of the emergency (*e.g.,* have the condition causing the emergency or the resulting public safety risks been resolved),

3. The status of pipeline operations affected by the gas pipeline emergency and when possible, a timeline for expected service restoration, and

4. Directions for the public to receive assistance (*e.g.,* provide a phone number for customers to call if they are without power for 24 hours, or directions to safe local shelters should temperatures drop below freezing).

PHMSA believes that providing in its regulations a list of information for operators to include in their procedures will help streamline communications to the public during a gas pipeline emergency and post-emergency efforts and ensure that members of the public have information needed to understand the risks to public safety posed by a gas pipeline emergency. In addition, by providing a list of minimum requirements for public communications, operators can train personnel on the type of information they should collect and share with the public. Operators can require the communication of additional information in their procedures, but should, at a minimum, inform the public of the information listed above. During an emergency response, an operator's resources may be strained such that not all the information pertaining to the incident may be available at a given time. Therefore, during a gas pipeline emergency on a distribution line, operators should provide updates to the public on a reasonable basis as this information becomes available or changes. This provision allows for a common-sense approach to when an operator must provide general public updates to an emergency. However, it would require operators to provide these updates based on the circumstances of the emergency such that the general public timely receives information that could influence the public's response to the emergency or benefit affected communities' understanding of recovery effort progress.

Further, PHMSA also proposes that when communicating this minimum information with the general public, operators must ensure these messages are issued in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's service area and are delivered in a manner accessible to diverse populations in their service operators. Operators should use clear and simple language in their communications. The Merrimack Valley incident underscores the value of such broadly accessible communications. The city of Lawrence, MA, is comprised of a higher percentage of Spanish-speaking residents than other areas affected by the Merrimack Valley incident. In the Massachusetts Emergency Management Agency (MEMA) After Action Report, MEMA reported that CMA did not fully account for the demographics of the impacted communities when attempting to communicate with the public during and following the incident, which in some cases delayed delivery of appropriate information and services to impacted customers.[121]

Operators must prepare their public communication plans before a gas pipeline emergency develops to ensure that the proper tools and resources are available to assist limited English proficiency (LEP) individuals in the communities they serve when an emergency arises. PHMSA notes that, as required under § 192.616(g), operators must conduct their public awareness program in other languages commonly understood by a significant number and

[120] Section 192.616 requires operators to develop and implement a written continuing public-education program that follows the guidance provided in American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference, see § 192.7). API RP 1162 is a consensus standard that establishes a baseline public-awareness program for pipeline operators. It states that operators should provide notice of, and information regarding, their emergency response plans to appropriate local emergency officials.

[121] Mass. Emergency Mgmt. Agency & Mass. Nat'l Guard, ''Merrimack Valley Natural Gas Explosions After Action Report,'' at 49–50 (Jan. 2020), *https://www.mass.gov/doc/merrimack-valley-natural-gas-explosions-after-action-report/download* (''Merrimack Valley After Action Report'').

concentration of the non-English speaking population in the operator's area. Therefore, operators should already be aware of the languages used in their service areas and have this information readily available. If operators do not already have this information, data from the U.S. Census Bureau American Community Survey at the tract level—including summarized information on English proficiency along with mapping of critical infrastructure and locations of hospitals, long-term care facilities, police, and fire stations—can help provide more targeted and community-specific services.[122] Operators can use this information to understand the demographics of their communities and build lists of common media sources for each language population in their service area. More information on how to reach LEP communities in emergency preparedness, response, and recovery is available through the Department of Justice.[123] Where appropriate, operators' communications during pipeline emergencies should account for disabilities that might make communication difficult by, for example, having American Sign Language interpreters present during press conferences to ensure that hearing-impaired residents can receive communications during a pipeline emergency.

3. Emergency Response Plans—Opt-in System for Customers

a. Current Requirements—Emergency Response Plans—Customers

As previously discussed, there are currently no Federal regulations in place that would require gas distribution operators to establish communications with customers throughout a gas pipeline emergency. There are also no current Federal requirements in place requiring these operators establish procedures for developing and implementing an opt-in communication system whereby customers in their service area can receive updates of pipeline emergencies on their cell phones or other media.

b. Need for Change—Emergency Response Plans—Customers

As the incident unfolded and local leaders made decisions to ensure the safety of citizens, each community sent their own evacuation notifications targeting their residents by using 9–1–1 call location data to estimate the locations of the affected services. Local officials used this data to reach a consensus about which areas to evacuate because they were unable to use more accurate data from CMA regarding the number and location of impacted customers.[124]

Andover and North Andover used their existing emergency notification systems to notify residents to evacuate. Authorities in North Andover issued a voluntary evacuation for all occupied structures with natural gas utility service, using local cable channels, the town website, and a citizen alert telephone system that sends public service messages. The alert system automatically called every landline. However, cell phones and private numbers had to be registered to receive a call. The Andover fire chief called for an evacuation using a citizen alert telephone system and social media. The wireless emergency alerts to evacuate South Lawrence, and later to return home, were sent out in both English and Spanish. The South Lawrence mayor's evacuation order was issued as an alert over cell phones and media broadcasts to residents in the area. In total, more than 50,000 residents were asked to evacuate through a variety of methods.

While many municipalities have communication systems to rapidly communicate with their constituents during an emergency, not all gas distribution operators are using these tools to rapidly communicate with their customers during a gas pipeline emergency. PHMSA believes that operators could use these tools to provide customers with real-time information during an emergency to protect public safety. The Merrimack Valley incident underscored the need for operators to improve their communication with customers when responding to an emergency on a gas distribution pipeline. Subsequently, 49 U.S.C. 60102 was amended to include a new mandate to expand the use of voluntary, opt-in customer notifications during an emergency. Specifically, PHMSA was directed to update its regulations to ensure that each emergency response plan developed by an operator of a gas distribution system includes written procedures for ''the development and implementation of a voluntary, opt-in system that would allow operators of distribution systems to rapidly communicate with customers in the event of an emergency.'' (49 U.S.C. 60102(r)(3)). PHMSA understands that a ''system'' to ''rapidly communicate with customers'' could take many forms; however, in practice, it is typically a ''reverse 9–1–1'' system that calls or texts individual customers to notify them of significant, time-sensitive events. Many cities and utilities already use such systems to allow emergency officials to notify residents and businesses of emergencies or outages by telephone, cell phone, text message, or email.

c. Proposal To Amend § 192.615—Emergency Response Plans—Customers

Pursuant to 49 U.S.C. 60102(r)(3), PHMSA proposes to add to § 192.615 a new paragraph (d) that would require operators of gas distribution pipelines to establish procedures for developing and implementing a voluntary, opt-in customer notification system to communicate with customers in the event of a gas pipeline emergency. PHMSA understands the statutory mandate for a ''voluntary, opt-in system'' to mean that the gas pipeline operators give the customers they serve the opportunity to opt-in (or opt-out) to receiving notifications from the operator's communication system, therefore making the system voluntary for customers. Gas distribution operators must notify all customers of the existence of such a communications tool and their ability to elect to receive such emergency notifications.

PHMSA does not expect that a voluntary, opt-in emergency notification system would impose a significant burden on operators. PHMSA notes that operators will often already have from their billing activities much of the information (customer phone numbers, email and postal addresses, and preferred language) needed to implement such a system. And because an iteration of a voluntary, opt-in or opt-out emergency notification systems may already be in place in some local communities,[125] PHMSA concludes that operators could comply with this proposed requirement by coordinating with cities and townships to utilize those existing systems. Where coordination with an existing communication system is not possible, operators may choose to utilize a third-party vendor or build such a service in-house. Regardless of who administers the notification system proposed in § 192.615(d), operators would need to provide a basic description of the system and describe the operation of the system in their procedures. Operators

[122] Ltd. English Proficiency, ''Data and Language Maps,'' U.S. DOJ, *https://www.lep.gov/maps* (last visited Feb. 27, 2023).

[123] U.S. DOJ, ''Tips and Tools for Reaching Limited English Proficiency in Emergency Preparedness, Response, and Recovery,'' (2016), *https://www.justice.gov/crt/file/885391/download.*

[124] Merrimack Valley After Action Report at 46.

[125] PHMSA further understands that some utilities (*e.g.,* electric utilities) may have similar notification systems for their customers and the public within their service areas.

must also include in their procedures a description of the protocols for activating the system and notifying customers (*i.e.,* who initiates the notification and when). PHMSA notes that such a voluntary opt-in or opt-out system could have additional benefits outside of gas pipeline emergencies, as operators could use such a system to communicate with their customers during non-emergencies (such as service outages or planned maintenance) or for billing purposes.

Because periodic testing is essential for ensuring proper operation of such an emergency customer notification system, PHMSA includes within its proposed § 192.615(d) that operators' procedures must describe system testing protocols and (at least) annual testing. Operators would need to maintain the results of their testing and operations history for at least 5 years. If an operator does not control the testing protocol (*e.g.,* because they rely on an emergency notification system administered by a local government), they should describe in their procedures the frequency of testing performed by partnered municipality and arrange to receive confirmation of those tests after they occur.

Similar to the requirements discussed earlier for public communications during and following gas pipeline emergencies, PHMSA is also proposing that an operator's written procedures for this opt-in notification system include a description of how the system's messages will be accessible to English-speaking and LEP customers alike. Operators should describe the process for identifying any LEP or other pertinent demographic information for the areas they serve. These procedures should include a description of any non-English languages required in standardized emergency communications that would be provided in an operator's system. Because there may be LEP individuals who need to receive these messages, operators should be prepared to translate messages about public safety into the required non-English language(s).

PHMSA also proposes to require operators' procedures include cybersecurity measures to protect the notification system and customer information. As with any system that interfaces with operators' information technology assets or customers private information, operators should protect against cybersecurity vulnerabilities and insider threats. Operators should, for example, include protocols aimed at protecting their infrastructure from malicious attacks, false notifications being sent to customers, and theft of customers' information. If the communication system is operated by a third party, operators should document the cybersecurity measures managed by the vendor.[126]

PHMSA proposes that operators of gas distribution systems must implement such a voluntary, opt-in notification system in accordance with their procedures (*i.e.,* ensure that the system is ready for use during a gas pipeline emergency) no later than 18 months after the publication of the final rule.[127] PHMSA proposes that 18 months after the publication of the final rule in this proceeding is a reasonable timeframe to implement these new procedures and seeks comment on this conclusion.

4. Emergency Response—Incident Command Systems

a. Background

Communication during a pipeline emergency is complex and includes communication between the pipeline operator, other pipeline companies, non-pipeline utilities, emergency responders, elected officials, PSAPs, and the public. Effective communication between and within each of these entities is crucial to the successful response to a gas pipeline emergency. For this reason, some gas distribution pipeline operators and other utilities use an Incident Command System (ICS) to coordinate emergency response actions.

An ICS is a standardized approach to the command, control, and coordination of on-scene management of emergencies and other incidents, providing a common hierarchy within which personnel from multiple organizations can be effective.[128] An ICS is the combination of procedures, personnel, facilities, equipment, and communications operating within a common organizational structure, designed to aid in the management of on-scene resources. It can be applied to incidents (including emergencies and planned events alike) of any size.

The National Incident Management System (NIMS), a system commonly used in the public and private sectors of incident management, uses ICS principles. As stated in the American Gas Association's (AGA) Emergency Preparedness Handbook, ''[u]tilities across our nation are increasingly integrating [NIMS] into their planning and incident management structure.'' [129] Additionally, API in API RP 1174 recommends the use of NIMS for responding to accidents on hazardous liquid pipelines.[130] FEMA has also indirectly recommended the use of NIMS through its recommendation of National Fire Protection Association (NFPA) Standard 1600 for emergency preparedness, a standard which recommends the use of NIMS.[131]

Typically, local authorities handle most incidents using the communications systems, dispatch centers, and incident personnel within their jurisdiction. For larger and more complex incidents, however, response efforts may rapidly expand to multi-jurisdictional or multi-disciplinary efforts requiring outside resources and support. Widespread use of ICSs could allow the efficient integration of outside resources and enable personnel from anywhere in the Nation to participate in the incident-management structure. Regardless of the size, complexity, or scope of the incident, the use of an ICS could benefit pipeline operators.

PHMSA is considering an ICS-based system in this rulemaking to provide safety benefits. However, PHMSA has preliminarily determined further input from the public would be beneficial in assessing the feasibility of doing so, as well as the best practices that would

[126] As discussed in Section I.A. of the preamble, the BIL provides funding for the Natural Gas Distribution Infrastructure Safety and Modernization Grant Program. Each applicant selected for grant funding under this notice must demonstrate, prior to the signing of the grant agreement, effort to consider and address physical and cyber security risks relevant to their natural gas distribution system and the type and scale of the project. Projects that have not appropriately considered and addressed physical and cyber security and resilience in their planning, design, and project oversight, as determined by the Department of Transportation and the Department of Homeland Security, will be required to do so before receiving funds for construction, consistent with Presidential Policy Directive 21—Critical Infrastructure Security and Resilience and the National Security Presidential Memorandum on Improving Cybersecurity for Critical Infrastructure Control Systems.

[127] While 49 U.S.C. 60109(e)(7)(C)(i)(II) directs gas distribution operators to make their updated emergency response procedures available to PHMSA or the relevant State regulatory agency no later than 2 years after issuing a final rule, it does not specify a deadline for operators to have implemented their customer notification systems.

[128] FEMA, ''Glossary of Related Terms, E/L/G 0300 Intermediate Incident Command System for Expanding Incidents, ICS 300'' at 6 (Mar. 2018), *https://training.fema.gov/emiweb/is/icsresource/assets/glossary%20of%20related%20terms.pdf.*

[129] AGA, ''Emergency Preparedness Handbook for Natural Gas Utilities'' at 10, *https://www.aga.org/wp-content/uploads/2022/12/aga-emergency-preparedness-handbook-2018.pdf.*

[130] API Recommended Practice 1174, ''Recommended Practice for Onshore Hazardous Liquid Pipeline Emergency Preparedness and Response'' at 26 (1st ed. Dec. 2015).

[131] NFPA, ''NFPA 1600: Standard on Continuity, Emergency, and Crisis Management'' (2019); FEMA, ''Fact Sheet: NIMS Recommended Standards'' (Jan. 4, 2007), *https://www.fema.gov/pdf/emergency/nims/fs_standards_010407.pdf.*

inform such a regulatory standard. Specifically, PHMSA is considering requirements under § 192.615 for operators of gas distribution pipelines to follow ICS procedures in response to gas pipeline emergencies. For example, PHMSA could require that operators of gas distribution pipelines develop written procedures in accordance with ICS tools and practices. An example of an ICS practice would be to identify the roles and responsibilities of emergency responders and communicate those responsibilities to designated personnel, which would be similar to the current requirements in § 192.615(c). PHMSA recognizes the benefit of pipeline operators using ICS for gas pipeline emergencies, as such an approach can help hone and maintain skills needed to coordinate response efforts effectively, even as poor implementation of an ICS may hinder effectiveness. For example, in the Merrimack Valley incident, both the operator and emergency responders had an ICS in their respective emergency response manuals; however, the ICS procedures were implemented with mixed results. While State and local emergency responders were able to effectively manage, organize, and coordinate the activities of multiple agencies serving in the emergency response by following the ICS, the NTSB concluded that CMA's Incident Commander (IC) struggled to manage the multiple competing priorities, such as communicating with affected municipalities, updating emergency responders, and shutting down the natural gas distribution system, which adversely affected the IC's ability to complete tasks in a timely manner.[132] The Merrimack Valley incident underscores that effective execution of an ICS is still dependent upon each operator's ability to implement the practices during a crisis.

PHMSA is also considering, if it determines to adopt requirements for operators of gas distribution pipelines to follow ICS procedures in response to gas pipeline emergencies, requiring operators to train personnel on ICS tools and practices. PHMSA expects that to develop an ICS for a response to gas pipeline emergencies, operator personnel would need to undergo extensive training and coordination exercises with first responders, and local and State public safety officials. FEMA provides free resources for implementing and training on ICS on their website.[133] Because this training is free, PHMSA expects there should be no upfront costs to provide training, however, there would be a burden in terms of time for operators to (1) take these trainings and (2) incorporate ICS tools and practices into their training and emergency response procedures. Further, the ICS tools and guidance are designed to be integrated into an organization's existing infrastructure, so PHMSA would not expect operators to have to hire additional personnel to meet a new requirement in its regulations for an ICS. PHMSA seeks comment on these assumptions.

b. Request for Input on the Adoption of ICS Requirements in PHMSA Regulations

PHMSA is seeking public comments regarding the potential adoption within the pipeline safety regulations of a requirement at § 192.615 that each operator employ an ICS for gas pipeline emergencies to include the following topics that could inform the specifics of any such requirement:

1. Should PHMSA promulgate new regulations requiring ICS for all gas distribution systems? Any other pipeline facilities?
2. If PHMSA were to adopt ICS requirements, should there be any exceptions from the ICS requirements?
3. Should PHMSA develop a standard for ICS or incorporate by reference an existing industry-based standard for ICS?
4. What are current sources of ICS training?
5. How long does it take, or would it take, for operators to train an employee on ICS tools and practices?
6. How often should qualified employees receive periodic training on ICS tools and practices?
7. What is an appropriate timeline for operators to incorporate ICS practices into their procedures if PHMSA were to promulgate an ICS standard?

PHMSA requests that commenters provide specific proposals for what provisions should be adopted or changes that should be made to the regulations related to the questions listed above.

In addition to the questions above, PHMSA requests commenters to provide information and supporting data related to:

1. The number of gas distribution operators that have currently adopted an ICS in their emergency procedures.
2. The technical feasibility, cost-effectiveness, and practicability of implementing any requirement for operators to adopt ICS.
3. The potential quantifiable safety and societal benefits of adopting ICS.
4. The potential impacts on small businesses adopting ICS.
5. The potential environmental impacts of adopting ICS.

D. Operations and Maintenance Manuals (Section 192.605)—Overpressurization

1. Current Requirements—O&M Manuals—Overpressurization

Section 192.605 includes minimum requirements for gas pipeline operators' procedural manuals for operations, maintenance, and emergencies. Section 192.605(a) requires gas pipeline operators to have ''a manual of written procedures for conducting operations and maintenance activities and for emergency response,'' otherwise known as an O&M manual. Operators must review and update this manual at intervals that do not exceed 15 months and at least once each calendar year. Appropriate parts of the manual must be kept where operations and maintenance activities take place.

Section 192.605(b) lists various procedures that each gas pipeline operator must include in the manual to provide safety during operation and maintenance. Among other requirements, § 192.605(b)(5) requires that the O&M manual include a procedure for ''[s]tarting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed in this part, plus the build-up allowed for operation of pressure-limiting and control devices'' in order ''to provide safety during maintenance and operations.''

Subpart L also requires an operator to ''keep records necessary to administer the procedures established under § 192.605.''[134] Among the records required to be kept and made available to operating personnel are ''construction records, maps and operating history,'' per § 192.605(b)(3). Sections 192.605(d)–(e) require an O&M manual to include procedures for both reporting safety-related conditions and for surveillance, emergency response, and accident investigations, respectively.

2. Need for Change—O&M Manuals—Overpressurization

Clearly written procedures aid in the successful execution of tasks and processes necessary to ensure a gas distribution pipeline system is operated and maintained in a safe manner. Overpressurizations, while rare, can cause a pipeline failure if not addressed in a timely manner. Including measures

[132] NTSB/PAR–19/02 at 45–47, 48–49.

[133] FEMA, ''National Incident Management System'' (May 24, 2022), *https://www.fema.gov/emergency-managers/nims.*

[134] 49 CFR 192.603(b).

in O&M manuals to respond to indications of an overpressurization can help ensure a timely, effective response.

As demonstrated by the Merrimack Valley incident, operators of gas distribution pipelines must be prepared to recognize and respond to overpressurization indications, as these events can have significant consequences for public safety and the environment. PHMSA regulations have a requirement in § 192.605(b)(5) for operators to have procedures for ''starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.'' To further reduce the likelihood of future incidents like the 2018 Merrimack Valley incident, however, PHMSA proposes to amend § 192.605 to ensure that operators explicitly account for overpressurization in their O&M procedures.

Subsequent to the 2018 Merrimack Valley incident, 49 U.S.C. 60102 was amended to require PHMSA to undertake a new rulemaking that would require operators of gas distribution systems to update their operations, maintenance, and emergency plans to include procedures for specific actions to be taken on receipt of an indication of an overpressurization on their systems. Those actions include an order of operations for immediately reducing pressure in, or shutting down portions of, the gas distribution system, if necessary. (49 U.S.C. 60102(s)). Amendments to 49 U.S.C. 60108 require gas distribution operators to make their updated O&M manuals available to PHMSA or the relevant State regulatory agency within 2 years after any final rule is issued and every 5 years thereafter.

3. Proposal To Amend § 192.605—O&M Manuals—Overpressurization

In this NPRM, PHMSA proposes to amend § 192.605 to require that operators of gas distribution pipelines establish procedures for responding to, investigating, and correcting the cause of overpressurization indications as soon as practicable. This will include specific actions to take and an order of operations for immediately reducing pressure in portions of the gas distribution system affected by the overpressurization, shutting down that portion, or taking other actions as necessary.

A timely response to an overpressurization event will require operators to promptly recognize overpressurization indications. Operator procedures would need to document potential overpressurization indications based on the design and operating characteristics of their systems. For example, a common indication of an overpressure condition would be an increase in pressure or flow rate outside of normal operating limits—but precisely how much a pressure change outside normal conditions would exceed MAOP will depend on the characteristics of that system.

PHMSA also proposes to require that an operator's procedures must document specific actions and the sequence of events various personnel must follow in response to an overpressurization indication. Those procedures should contain clear statements of authority for relevant operator personnel to undertake particular actions both on initial receipt of notification of an overpressurization indication and subsequent confirmation that an overpressurization condition exists or is imminent.[135] An example would include the actions a controller in the monitoring center (*i.e.,* SCADA system) would take and the protocols to follow when in receipt of a pressure alarm indicating an overpressurization. Similarly, field personnel may witness overpressurization indications such as fires, explosions, control lines damage during excavation, instrumentation or valve failures, or the activation of safety valves. Operators must develop procedures for those personnel to recognize the signs of an overpressurization as well as identify the steps they should take in response (such as applying a stop-work authority, reducing the pressure, isolating portions of the gas distribution system, and notifying emergency responders). The operator must also provide training on these procedures to ensure that personnel—including field personnel and construction workers—are able to recognize the indications of an overpressurization and respond appropriately.[136]

Operators must also develop and document procedures for, as soon as practicable, investigating and correcting the cause of an overpressurization or an overpressurization indication. While the amendments proposed throughout this NPRM, if adopted, are expected to prevent or reduce the frequency of future overpressurizations, they may still occur. If an operator experiences an overpressurization or any indication that an overpressurization could occur, PHMSA proposes to require operators to investigate and correct the cause(s) of the overpressurization or overpressurization indication. During their investigation, operators could find a mode of failure common to other parts of their systems and take action to prevent or mitigate a potential overpressurization, such as promptly repairing or replacing parts of the system.

PHMSA proposes the requirements described above to ensure operators have clear direction as to what procedures are necessary to prevent catastrophic overpressurizations similar to that of the Merrimack Valley incident and to improve the safety of gas distribution systems generally. PHMSA also expects this proposed amendment of subpart L requiring distribution operators to update O&M manuals to address overpressure scenarios would reinforce the updates to DIMP plans proposed elsewhere in this NPRM. PHMSA expects that this amendment would improve pipeline safety by bringing additional awareness to gas distribution pipeline operators and personnel regarding overpressurization indications. This amendment would also ensure operators establish procedures for monitoring and controlling gas pressure should they detect an indication of an overpressurization. PHMSA further proposes to respond to the risk of overpressurization in an operator's O&M manuals through adopting an MOC process, as discussed below.

PHMSA understands these proposed requirements for enhancements of gas distribution operators' O&M manuals to address a well-understood threat to pipeline integrity would be reasonable, technically feasible, cost-effective, and practicable for gas distribution operators. PHMSA expects that some gas distribution operators may already be complying with these requirements either voluntarily (*e.g.,* in response to the Merrimack Valley incident), as a result of similar requirements imposed

[135] Although PHMSA expects that among the immediate actions that operators will take in response to an overpressurization indication would be confirming as soon as practicable whether an overpressurization exists or is imminent, operators may not delay other immediate actions necessary to protect hazards to public safety and the environment while they obtain such confirmation.

[136] PHMSA also notes that pipeline employees and contractors who raise concerns that a pipeline operator is not complying with pertinent PHMSA safety requirements or the pipeline's implementing procedures may have statutory whistleblower protections pursuant to 49 U.S.C. 60129. Pipeline employees and contractors who are concerned that they have been retaliated against for raising safety concerns should be raised with Department of Labor (via the Occupational Health and Safety Administration). *See* OHSA, ''Fact Sheet: Whistleblower Protection for Pipeline Facility Workers,'' (Feb. 2022), *https://www.osha.gov/sites/default/files/publications/OSHA4072.pdf.*

by State pipeline safety regulators, or pursuant to their DIMPs. PHMSA further notes that its proposed enhancements of baseline expectations for O&M manual contents are precisely the sort of minimal actions a reasonably prudent operator of gas distribution pipeline facility would adopt in ordinary course to protect public safety given that their systems transport pressurized (natural, flammable, toxic, or corrosive) gasses typically within or in close proximity to population centers. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the public safety and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their O&M manuals (and manage any related compliance costs).

E. Operations and Maintenance Manuals (Section 192.605)—Management of Change

1. Current Requirements—O&M Manuals—Management of Change (MOC)

There are no current requirements in the pipeline safety regulations for operators of gas distribution pipelines to follow management of change (or MOC) processes in their operations and maintenance activity. While not specifically an MOC process, the operator qualification provisions in § 192.805(f) require that changes that affect covered tasks be communicated to individuals performing these tasks. As such, operators may have in place some type of process for reviewing changes, including whether such changes will impact O&M procedures and those performing the procedures. Further, gas transmission pipelines located in a high consequence area have an MOC requirement in § 192.911(k), which adopts an MOC process outlined in the American Society of Mechanical Engineers/American National Standards Institute (ASME/ANSI) standard B31.8S, section 11.[137] The 192.911(k) requirement, however, applies only to operators of gas transmission pipelines subject to subpart O integrity management requirements (*i.e.,* high-consequence areas, which are not applicable to gas distribution pipelines).

2. Need for Change—O&M Manuals—MOC

Inadequately reviewed or documented design, construction, maintenance, or operational changes can seriously impact pipeline integrity. MOC procedures are designed to prevent such impacts. In the Merrimack Valley incident, NTSB investigators discovered omissions in CMA's engineering work package and construction documentation for the South Union Street project and that the work package was completed without a proper constructability review. NTSB investigators reviewed the engineering plans that CMA used during the construction work and found that the CMA engineers did not document the location of regulator control lines.[138] Had CMA accurately documented the regulator control lines, engineers and work crews would have been able to relocate them prior to abandoning the pipeline main.

CMA did not employ MOC processes for its maintenance and construction operations. Instead, CMA's engineering department relied on simple checklists in its workflow documentation. The NTSB determined that if NiSource had adequately employed a MOC process, it could have identified potential risk of overpressurization of its system from a common mode of failure as a result of the South Union Street project construction activity and employed control measures to prevent or mitigate the Merrimack Valley incident. As a result, the NTSB recommended in P–18–8 that NiSource apply an MOC process to all changes to adequately identify system threats that could result in a common mode of failure.[139]

NTSB also stated that CMA did not identify the omission of regulator control lines from its engineering work package during its constructability review of that documentation. Constructability reviews—an element of MOC processes—are recognized and accepted as a necessary engineering practice for the execution of construction services. If properly implemented, constructability reviews provide structured reviews of construction plans and specifications to ensure functionality, sustainability, and safety, thus reducing the potential for shortcomings, omissions, inefficiencies, conflicts, or errors. The NTSB concluded that the CMA constructability review process was not sufficiently robust to detect the omission of a work order to relocate the sensing lines. The NTSB identified that part of the failure of the process was likely due to the absence of a review by a critical department (CMA's measurement and regulation or M&R department). Despite there being at least two constructability reviews for the South Union Street project, the M&R department did not participate. The NTSB stated that a comprehensive constructability review, which would require all pertinent departments to review each project, along with the endorsement by a professional engineer (PE), would likely have identified the omission of the regulator control lines, thereby preventing the error that led to the Merrimack Valley incident. As a result of its investigation, the NTSB recommended that NiSource revise its constructability review process to ensure that all pertinent departments review construction documents for accuracy and completeness, and that the documents or plans be endorsed by a PE prior to commencing work.

Subsequent to the 2018 Merrimack Valley incident, PHMSA was required by statute to update its regulations to require gas distribution operators to include in their O&M manuals an MOC process which must apply to ''significant technology, equipment, procedural, and organizational changes to the distribution system[.]'' (49 U.S.C. 60102(s)(2)). This provision also requires that operators ''ensure that relevant qualified personnel, such as an engineer with a professional engineer licensure, subject matter expert, or other employee who possesses the necessary knowledge, experience, and skills regarding natural gas distribution systems, review and certify construction plans for accuracy, completeness, and correctness.'' In addition, 49 U.S.C. 60108 requires gas distribution operators to make their updated O&M manuals available to PHMSA or the relevant State regulatory agency within 2 years after the final rule is issued in this proceeding and every 5 years thereafter.

3. Proposal To Amend § 192.605 To Require an MOC Process

Pursuant to 49 U.S.C. 60102(s), PHMSA proposes to require that gas distribution operators update their O&M manuals to include a detailed MOC process.[140] Under this proposal,

[137] Am. Soc'y of Mech. Eng's, ANSI B31.8S–2004, ''Managing System Integrity of Gas Pipelines'' (Jan. 14, 2005).

[138] NTSB/PAR–19/02 at 16.

[139] NTSB/PAR–19/02 at 51.

[140] PHMSA has not included its proposed MOC requirements for distribution pipeline operators within integrity management regulations at 49 CFR part 192, subpart P (as it did for gas transmission pipelines within subpart O) because 49 U.S.C.

Continued

operators would be required to apply an MOC process to technology, equipment, procedural, and organizational changes that may impact the integrity or safety of the gas distribution system. Specifically, operators must apply an MOC process to changes to their pipeline systems, organization, and O&M procedures in connection with the (1) installation, modification, or replacement of, or upgrades to, regulators, pressure monitoring locations, or overpressure protection devices; (2) modifications to alarm set points or upper/lower trigger limits on monitoring equipment; (3) introduction of new technologies for overpressure protection into the system; (4) revisions, changes to, or introduction of new standard operating procedures for design, construction, installation, maintenance, and emergency response; and (5) other changes that may impact the integrity or safety of the gas distribution system. PHMSA notes that although most of the occasions for changes to operator pipelines and procedures listed above are directed toward reducing the potential for overpressurization, it expects that MOC processes will also help reduce the risk of other incidents on gas distribution pipelines. Towards that end, PHMSA proposes savings language (''other changes that may impact the integrity or safety of the gas distribution systems'') that would require operators to employ a MOC process in connection with changes to their systems and procedures in connection with high-risk activities.

PHMSA also proposes to require that the MOC process must ensure that qualified personnel review and certify construction plans associated with installations, modifications, replacements, or upgrades for accuracy and completeness before the work begins. These personnel must be qualified to perform these tasks under subpart N of 49 CFR part 192.[141] Qualified personnel could include an engineer with a professional engineer (PE) license, a subject matter expert, or any other employee who possesses the necessary knowledge, experience, and skills regarding gas distribution systems. This proposal would ensure that personnel who work on planning construction projects have the appropriate qualifications and training necessary to ensure these tasks are performed safely.

In developing this proposed requirement, PHMSA reviewed NTSB recommendation P–19–16, which called on states to require that all future gas infrastructure projects require licensed PE approval and stamping.[142] This NPRM in no way prohibits states from applying a higher standard than that provided in the Federal regulations. Additionally, PHMSA acknowledges that a PE could provide the best assurance of high-quality review of construction plans. PHMSA is uncertain as to the availability of those personnel resources in all states or for all gas distribution operators, however, and any shortage of licensed PEs could cause delays in the construction or remediation of integrity issues. Other qualified professionals, such as experienced engineers or subject matter experts, may have an equivalent level of experience or skills without holding the licensure. PHMSA is proposing this amendment pursuant to 49 U.S.C. 60102(s), which contemplates a larger pool of personnel qualified to perform these reviews and certifications than just licensed PEs. Nevertheless, PHMSA expects that when operators evaluate construction projects, operators consider assigning qualified personnel with experience commensurate to the complexity of each project and its potential impacts on public safety and the environment. The most complex and riskiest projects should be reviewed by a licensed PE, if available, while less complex or routine construction projects may be suitable for review by qualified personnel who do not hold such a credential. PHMSA welcomes comments on the availability of PE licensure in various jurisdictions and the appropriateness of review by other, non-licensed qualified individuals.

Finally, PHMSA proposes to require that operators' MOC process must ensure that any hazards introduced by a change are identified, analyzed, and controlled before resuming operations. Quality originates at the planning stages of a pipeline project. When pipeline facilities are designed or modified, operators intend for these changes to provide decades of safe and reliable operation. But any change to a pipeline system can also introduce potential hazards. Operators can manage risks introduced by changes to the system through a robust MOC process. It is a standard practice in any MOC process or system to analyze and control for risks. PHMSA is proposing this general requirement for operators to identify any hazards they are introducing as the result of a change, to analyze those risks, and to control for those hazards and risks through preventive and mitigative measures. These steps are necessary to establish appropriate preventive and mitigative measures to reduce the likelihood and consequences of failure on a gas distribution system should an accident occur. PHMSA, therefore, proposes this requirement to ensure that operators incorporate these steps into their MOC process.

PHMSA understands this proposed requirement for gas distribution operators' O&M manuals to incorporate a MOC process would be reasonable, technically feasible cost-effective, and practicable. PHMSA expects that some gas distribution operators may already comply with these requirements either voluntarily (*e.g.,* to minimize losses of commercially valuable commodities, in response to the Merrimack Valley incident and NTSB recommendations, or consistent with broadly applicable, consensus industry standards such as ASME/ANSI B31.8S[143]), as a result of similar requirements imposed by State pipeline safety regulators, or as risk mitigation measures pursuant to their DIMPs. PHMSA further notes that the proposed construction plans certification requirement within those MOC procedures is consistent with longstanding industry best practices and NTSB recommendations; PHMSA's proposal also affords operators optionality to use either their own or contractor personnel when implementing this requirement on a going-forward basis. Indeed, PHMSA submits that its proposed enhancements of baseline expectations for O&M manual contents are precisely the sort of minimal actions a reasonably prudent operator of gas distribution pipeline facility would adopt in ordinary course to protect public safety given that their systems transport pressurized (natural, flammable, toxic, or corrosive) gasses typically within or in close proximity to population centers. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would

60102(s) explicitly required update of regulations governing ''procedural manuals for operations, maintenance, and emergencies''—located at § 192.605.

[141] ''Qualified'' under § 192.803 means that an individual has been evaluated pursuant to the requirements of Subpart N and can perform assigned covered tasks and recognize and react to abnormal operating conditions.

[142] NTSB/PAR–19/02 at 50.

[143] ASME/ANSI, B31.8S–2004, ''Managing System Integrity of Gas Pipelines, Supplement to B31.8'' (Jan. 14, 2005) (incorporated by reference under § 192.7).

necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their O&M manuals and identify or procure personnel resources needed to comply with the new certification requirement (and manage any related compliance costs).

PHMSA is also requesting comments on whether it should promulgate the MOC requirement described above, adopt the industry standard ASME/ANSI B31.8S for gas distribution operators, or both.[144] PHMSA has adopted ASME/ANSI B31.8S for gas transmission operators subject to 49 CFR, part 192, subpart O integrity management requirements. Specifically, PHMSA at § 192.911(k) requires operators of certain gas transmission pipelines to develop and follow an MOC process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. While provisions in section 11 of ASME/ANSI B31.8S outline formal elements of an MOC process resembling the elements within the regulatory text proposed in this NPRM, other provisions of ASME/ANSI B31.8S section 11, such as (b)(1), are specific to changes in population that may be more appropriate for gas transmission operators required to identify high consequence areas (HCAs) along their pipeline. But the HCA concept does not apply to gas distribution operators, and as noted above, PHMSA expects it can capture the public safety and environmental benefits from MOC processes by adopting the regulatory text proposed in this NPRM without incorporating by reference ASME/ANSI B31.8S directly. Nevertheless, PHMSA requests comments on whether adoption within a final rule of a similar approach for gas distribution operators would provide better protection for public safety and the environment, and otherwise be technically feasible, cost-effective, and practicable.

F. Gas Distribution Recordkeeping Practices (Section 192.638)

1. Current Requirements—Recordkeeping

Operators must collect and maintain records about their gas distribution pipelines in compliance with requirements of 49 CFR part 192, including those governing DIMPs. Section 192.1007(a) requires operators to identify reasonably available information necessary to develop an understanding of the characteristics of their pipelines, identify applicable threats, and analyze the risk associated with the threats. Section 192.1007(a)(3) requires that operators have a plan to collect information needed to conduct the risk analysis required in DIMP. Section 192.1007(a)(5) requires operators to capture and retain information on any new pipeline installed, including, at a minimum, the location of the pipeline and the material of which it is constructed.

In addition to keeping records as part of complying with DIMP requirements, an operator must also consider the data it needs to comply with the various recordkeeping requirements in 49 CFR part 192, such as those for pipeline design, testing and construction (§ 192.517); corrosion control (§ 192.491); customer notification (§ 192.16); uprating (§ 192.553); surveying, patrolling, monitoring, inspections, operations, maintenance, and emergencies (§§ 192.603 and 192.605); and operator qualification (§ 192.807). Sections 192.603(b) and 192.605 further require that each operator establish a written operating and maintenance plan that meets the requirements of the pipeline safety regulations and keep records necessary to administer the plan. Sections 192.603(b) and 192.605(e) require operators to maintain current records and maps of the location of their facilities for use in operations, maintenance, and emergency response activities (*e.g.,* surveillance, leak surveys, cathodic protection, etc.). Further, § 192.605 requires that operators make construction records, maps, and the pipeline's operating history available to appropriate operating personnel. Therefore, if an operator requires maps as a record to properly administer its O&M procedures consistent with Federal safety requirements, these maps must be maintained by the operator.

Additionally, operators must keep records related to the design and installation of their pipeline components, including protection against overpressurization under 49 CFR part 192, subparts L and M.[145] These records would include valve failure position and capacity records, which include information operators used when designing the system to ensure sufficient overpressure protection.

2. Need for Change—Recordkeeping

Maintaining accurate and reliable records is critical for safe operation, maintenance, pipeline integrity management, and emergency response. Records of the physical components on a gas distribution system, such as regulators, valves, and underground piping (including control lines), are necessary for an operator to have the basic knowledge of its system needed to maintain control of system pressure. Mapping of all gas systems enables proper planning of system upgrade activities, maintenance, and protection of the system from excavation damage. Knowing the location of control lines is critically important to preventing incidents on low-pressure distribution systems because they can be easily damaged during excavation activities or inadvertently taken out of service, as demonstrated by the Merrimack Valley incident. Further, mapping of all gas systems, such as documenting the location of shutoff valves, could improve the response time during an emergency. In the event of an incident or other emergency, being able to locate and operate valves is critical to achieving the effective shutdown and isolation of any sections of a gas distribution system. Incomplete, inaccurate, unreliable, or inaccessible records hinder the safe operation of a pipeline, reduce the effectiveness of the integrity assessment (as required under DIMP regulations), and impede timely emergency response.

The 2018 Merrimack Valley incident illustrated how incomplete records of gas distribution systems can lead to or exacerbate safety issues. One of the issues identified in the NTSB's report was that the engineers responsible for developing CMA's construction plan did not have all the records necessary to plan the construction project correctly, such as control line drawings and location information. Further, the CMA engineers knew that even if they had access to the records regarding the location of the control lines, the records CMA maintained were often outdated, and thus potentially inaccurate and incomplete.[146] For example, for the Winthrop regulator station, the records had the location of the control lines as

[144] On January 15, 2021, PHMSA issued the NPRM, ''Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Amendments,'' which included a proposal to replace the incorporated by reference ASME/ANSI B31.8S 2004 edition to the 2016 edition. 86 FR 3938, 3944 (Jan. 15, 2021). PHMSA reviewed both 2004 and 2016 editions for consideration in this rulemaking.

[145] *See* §§ 192.603(b), 192.605(b)(1), and subpart M (incorporating §§ 192.199 and 192.201).

[146] NTSB/PAR–19/02 at 16–17.

they existed around May 2010; however, CMA installed a new control line around September 2015 and never updated its records to reflect the change. Without access to accurate maps and drawings of the system, CMA did not include control line maps or procedures for handling control line removal in the construction plan. CMA then passed along an inaccurate and incomplete construction plan to the contractor doing the work. As a result, NTSB recommended that NiSource review and ensure that all records and documentation of its natural gas systems are traceable, reliable, and complete.

The Merrimack Valley incident further illustrated how the lack of accurate maps of pipeline systems can inhibit effective emergency response. During the emergency response to the overpressurization, the operator took too long to provide maps of the low-pressure system to emergency response officials, who needed street maps showing the layout of the natural gas distribution system to understand where the affected customers were located. CMA did not provide the information requested until hours after the overpressurization began. The emergency responders emphasized to the NTSB that the absence of this information impeded their emergency response and public safety decision-making. Without maps of the low-pressure system, the ICs managing emergency response had to evacuate thousands of people from their homes, including people in unaffected areas, out of an abundance of caution.

Subsequent to the 2018 Merrimack Valley incident, 49 U.S.C. 60102 was amended to ensure that operators keep better, more complete records (such as maps that include the location of control lines and other critical infrastructure) and make those available to the emergency responders and public officials who need them. Specifically, 49 U.S.C. 60102(t)(1) directs PHMSA to issue regulations that require distribution pipeline operators to identify and manage ''traceable, reliable, and complete'' maps and records of critical pressure-control infrastructure, and update other records needed for risk analysis. Operators must update their records ''on an opportunistic basis.'' These records must be accessible to all personnel responsible for performing or overseeing relevant construction or engineering work. Pursuant to 49 U.S.C. 60102(t)(1), PHMSA proposes to amend its regulations to supplement existing requirements pertaining to gas distribution operators' recordkeeping critical to pressure control on their systems. The proposal would require operators to collect or generate complete, reliable, and accurate records if they are not available, and make the records accessible to the personnel who need them.

3. Proposal To Add a New § 192.638—Records: Distribution System Pressure Controls

PHMSA proposes a new § 192.638 to specify that an operator of a gas distribution system must identify and maintain traceable, verifiable, and complete records documenting the characteristics of the pipeline critical to ensuring proper pressure controls.[147]

In 2019, PHMSA introduced a regulatory amendment requiring gas transmission records pertaining to MAOP to be ''traceable, verifiable, and complete.'' [148] 49 U.S.C. 60102(t)(1) similarly requires PHMSA to require operators to identify and manage ''traceable, reliable, and complete'' records. PHMSA understands that the phrase ''traceable, reliable, and complete,'' as used in 49 U.S.C. 60102(t)(1) is substantively the same standard with respect to the quality and accessibility of records maintained as the ''traceable, verifiable, and complete'' language adopted in the 2019 final rule for gas transmission pipelines.[149] PHMSA interprets ''reliable'' as used in 49 U.S.C. 60102(t)(1) to mean the same as ''verifiable'' as used in the 2019 rule because both verifiable and reliable would mean to prove that a record is trustworthy and authentic. A record is considered reliable if it is verifiable and vice versa. PHMSA's proposed § 192.638 recordkeeping requirement is intended to encompass any records essential to pressure control on a system and not just pertain to MAOP or material property and attribute verification activities. PHMSA would require operators to identify what records they currently have that document the characteristics of the pipeline that are ''critical to ensuring proper pressure controls'' for the system.

In § 192.638(a), PHMSA identifies the types of records that it proposes are critical to ensuring proper pressure control for a gas distribution system. These records include: (1) current location information (including maps and schematics) for regulators, valves, and underground piping (including control lines); (2) attributes of the regulator(s), such as set points, design capacity, and the valve failure position (open/closed); (3) the overpressure protection configuration; and (4) other records deemed critical by the operator.

Regarding item (1), operators generally keep records, such as maps and schematics, when designing their system and district regulator stations. Operators should also have records of selected regulators, valves, and other gas pressure control equipment based on several factors, for the purpose of determining, for example, the overall capacity and future flow requirements of the system.

Regarding item (2), records related to the attributes of the regulators' set points, design capacity, and valve failure position are necessary to ensure that the design of the district regulator station can protect the distribution system from overpressurization. For example, demands on the system may change over time due to customer usage, weather, or maintenance requirements. Operators can use design capacity records to validate and revalidate that their systems are capable of meeting changing customer demands and weather dynamics.

Regarding item (3), maintaining records for the overpressure protection configuration are necessary for the safe operation of the pipeline and for performing a robust risk analysis required under DIMP regulations. As demonstrated by the 2018 Merrimack Valley incident, certain overpressure protection configurations on low-pressure distribution systems (*i.e.,* redundant worker-monitor regulators) alone are inadequate for preventing an overpressurization. Requiring operators to keep records of their systems' overpressure configurations will ensure that operators will be able to identify any higher-risk configurations in their systems. Once identified, operators can properly assess the overall risk to their systems and take preventive or mitigative actions to reduce the likelihood or consequences of a potential failure.

Regarding item (4), PHMSA proposes that operators must have traceable, verifiable, and complete records for any records they deem critical but that were

[147] As discussed elsewhere in the preamble, PHMSA also proposes to introduce a cross-reference to this new § 192.638 within its existing DIMP plan knowledge management requirements at § 192.1007(a)(3).

[148] ''Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments,'' 84 FR 52180 (Oct. 1, 2019).

[149] *Compare* 192.607 (requiring ''traceable, verifiable, and complete records'' of certain material properties and attributes) *and* 192.624 (requiring ''traceable, verifiable, and complete records'' for MAOP confirmation) *with* 49 U.S.C. 60102(t) (requiring gas distribution operators identify and manage ''traceable, reliable, and complete records . . . critical to ensuring proper pressure controls for a gas distribution system . . . .'').

not mentioned in the list provided by PHMSA. This general requirement would ensure that operators keep records based on the unique characteristics of their system.

When taking inventory of the records described above, operators must identify if those records are traceable (*e.g.,* can be clearly linked to original information about, or changes to, a pipeline segment, facility, or district regulator station), verifiable (*e.g.,* their information is confirmed by other complementary but separate documentation), and complete (*e.g.,* as evidenced by a signature, date, or other appropriate marking such as a corporate stamp or seal). This amendment would improve the completeness and accuracy of the records needed during normal operations, emergency response activities, and risk analyses.

In § 192.638(b), PHMSA proposes to require that if an operator does not yet have traceable, verifiable, and complete records, then the operator must develop a plan for collecting those records. PHMSA also proposes to revise § 192.605 to ensure that operators have procedures for implementing the new recordkeeping requirements proposed in § 192.638. Because the availability and form of records, as well as records retention practices, will vary among operators, PHMSA proposes that operators must identify what records they need to collect under this requirement.

In § 192.638(c), PHMSA proposes that operators must collect records needed to meet this standard on an opportunistic basis, which is defined as occurring during normal operations conducted on the pipeline including (but not limited to) design, construction, operations, or maintenance activities. PHMSA notes that its proposed language in paragraph (c) mirrors the language at § 192.1007(a)(3) governing operator knowledge management in connection with a performance of the risk analysis within their DIMPs. PHMSA expects this approach will minimize compliance burdens on operators, as they would be able to collect or generate records through existing regulatory mechanisms such as DIMPs or annual inspections. PHMSA also proposes to revise § 192.1007(a)(3) so that it references § 192.638(c). This would require operators to identify records specified in § 192.638(c) that they could collect as part of their DIMP plan.

In § 192.638(d), PHMSA proposes to require that operators ensure the records required in this section are accessible to personnel performing or overseeing design, construction, operations, and maintenance activities. In the 2018 Merrimack Valley incident, the engineering staff did not have access to the maps containing control line information and were unaware if the department had access to such records. This lack of access and awareness resulted in the omission of critical information that should have been considered through a proper risk analysis under their DIMPs. Therefore, PHMSA proposes to add a requirement for operators to provide the personnel responsible for planning and performing work on critical infrastructure with the records they need to perform their work safely and effectively. Operators should note that access would extend to the qualified employees monitoring the gas pressure (as proposed in § 192.640). PHMSA expects that during a construction activity, these qualified personnel may need records such as maps of control lines to effectively monitor the safety of excavation activities around gas distribution systems.

In § 192.638(e), PHMSA proposes to require that once a record is generated or collected under this section, that operators must keep the record for the life of the pipeline. This will help facilitate traceability of records as required by 49 U.S.C. 60102(t).

In § 192.638(f), PHMSA specifies that the requirements in this section would not apply to master meter systems, liquefied petroleum gas (LPG) distribution pipeline systems that serve fewer than 100 customers from a single source, or any individual service line directly connected to a transmission, gathering, or production pipeline that is not operated as part of a distribution system. As discussed above, small LPG operators are relatively simple, low-risk systems affecting a finite (generally small) number of customers such that the public safety and environmental benefits from imposing new requirements on these systems would be limited. Similar reasoning applies to master meter systems. PHMSA understands that compliance costs generally are felt more acutely by small LPG operators and master meter system operators. PHMSA does not expect that these operators would have the means (*e.g.,* access to detailed maps and GIS tools) to be able to comply with the recordkeeping requirements proposed in this NPRM. For individual service lines, the consequences of an overpressurization are smaller relative to a district regulator station. Given the relatively low public safety and environmental benefits from extending the new § 192.638 recordkeeping requirements to those operators, PHMSA proposes to except those systems from the new recordkeeping requirement at § 192.638. Nevertheless, PHMSA does encourage these excepted operators to, where applicable, follow the recordkeeping specifications proposed in this NPRM.

Overall, PHMSA expects that its proposed new § 192.638 would ensure that operators are documenting and maintaining records of how their critical pressure controlling facilities operate so that they can review and assess their performance over time. Keeping complete and accurate records for the life of these assets could help improve operators' risk analyses, as required by DIMP regulations, and thus improve the overall integrity of gas distribution pipelines.

PHMSA also understands this proposed requirement for gas distribution operators to identify and maintain traceable, accurate, and complete records documenting system characteristics pertinent to pressure control would be reasonable, technically feasible, cost-effective, and practicable. As explained above, the proposed requirement is analogous to material property documentation requirements elsewhere in PHMSA regulations (*e.g.,* § 192.607) for gas transmission systems. And PHMSA understands that some gas distribution operators may already comply with this proposed requirement either voluntarily (*e.g.,* to minimize losses of commercially valuable commodities, in response to the Merrimack Valley incident and NTSB recommendations, or consistent with broadly applicable, consensus industry standards such as ASME/ANSI B31.8S [150]), as a result of similar requirements imposed by State pipeline safety regulators, or as risk mitigation measures pursuant to their DIMPs. Indeed, the sort of records subject to this proposed requirement are precisely the sort of records that a reasonably prudent operator of gas distribution pipeline facility would in ordinary course already have identified and be maintaining to protect the public given that their systems transport pressurized (natural, flammable, toxic, or corrosive) gasses typically within or in close proximity to population centers. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its

[150] ASME/ANSI, B31.8S–2004, ''Managing System Integrity of Gas Pipelines, Supplement to B31.8'' (Jan. 14, 2005) (incorporated by reference under § 192.7).

supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to review and compile pertinent existing records and develop and implement procedures to generate or obtain missing records on a going-forward basis (and manage any related compliance costs).

G. Distribution Pipelines: Presence of Qualified Personnel (Sections 192.640 and 192.605)

1. Current Requirements—Procedures for Qualified Personnel Monitoring Gas Pressure

Currently, PHMSA does not require operators to have procedures for monitoring gas pressure with qualified persons and equipment capable of ensuring pressure control and having the ability to shut off the flow of gas. There are other provisions related to personnel qualification included in 49 CFR part 192, subpart N, which contain requirements for operators of gas pipelines to develop a qualification program to qualify employees for certain covered tasks. Covered tasks include those activities that affect the operation or integrity of the pipeline. PHMSA defines ''Qualified'' in § 192.803 to mean that ''an individual has been evaluated and can: (a) [p]erform assigned covered tasks; and (b) [r]ecognize and react to abnormal operating conditions.''

2. Need for Change—Distribution Pipelines: Presence of Qualified Personnel

Gas pipelines are often monitored in a control room by controllers using computer-based equipment, such as a SCADA system, that records and displays operational information about the pipeline system, such as pressures, flow rates, and valve positions. Some SCADA systems are used by controllers to operate pipeline equipment remotely or automatically; in other cases, controllers may dispatch other personnel to operate equipment in the field. For those operators whose systems are not capable of remote or automatic shut down or pressure control, control room operators may have to respond to overpressure indications by communicating to field personnel to go to the location of the suspected event, gather additional information to determine if there is an emergency, and initiate response actions, if needed. This process creates delays in identifying and responding to overpressurization indications on gas distribution systems.

During the Merrimack Valley incident, the SCADA controller responded to a high-pressure alarm by contacting the field technician who could adjust the flow of gas at the Winthrop regulator station. CMA's system had remote pressure monitoring but no remote or automatic shutoff. It took 30 minutes from the time CMA's SCADA controller noticed an alarm to the time when the field technician began to adjust the flow of gas. NTSB investigators learned that, at one time, CMA required that a technician monitor any gas main revision work that required depressurizing the main.[151] Per those historical procedures, the technician would use a gauge to monitor the pressure readings on the impacted main and would communicate directly with the crew performing the work. If a pressure anomaly occurred, the technician could quickly act to prevent an overpressurization event. CMA offered no explanation to the NTSB as to why this procedure was phased out.

As a result of the incident, the NTSB recommended in P–18–9 that NiSource, Inc., develop and implement control procedures during modifications to gas distribution mains to mitigate the risks identified during MOC operations, and stated that gas main pressures should be continually monitored during these modifications and that assets should be placed at critical locations to immediately shut down the system if abnormal operations are detected. PHMSA agrees with NTSB's recommendation and concludes that requiring these procedures could benefit safety for all gas distribution operators. Further, PHMSA believes that operators can mitigate the consequences of the overpressurization by requiring qualified personnel capable of shutting off the gas to monitor the gas pressure during construction associated with installations, modifications, replacements, or upgrades on gas distribution mains that could result in overpressurization.

Subsequent to the 2018 Merrimack Valley incident, PHMSA was directed to issue regulations requiring qualified personnel of a gas distribution system operator, with the ability to ensure proper pressure control and shut off, or limit gas pressure should overpressurization occur, monitor gas pressure at district regulator stations during certain times. (49 U.S.C. 60102(t)(2)). The mandate specifies that those times are during any construction project that has the potential to cause an overpressurization, including projects such as tie-ins or abandonment of distribution mains. These requirements do not apply if a district regulator station has a monitoring system and the capability of remote or automatic shutoff. Further, amendments to 49 U.S.C. 60108 now require gas distribution operators to make their updated O&M manuals available to PHMSA or the relevant State regulatory agency within 2 years after any final rule is issued and every 5 years thereafter.

3. Proposal To Add a New § 192.640 Distribution Pipelines: Presence of Qualified Personnel

In a new § 192.640, PHMSA proposes an additional layer of safety at district regulator stations during construction projects by requiring qualified personnel to be present, monitor the gas pressure, and have the capability to shut off the flow of gas during an overpressurization event. This provision, including each of the below proposed parts, would not apply if an operator already has equipped that district regulator station with a remote pressure monitoring system that has the capability for remote or automatic shutoff.[152]

In paragraph (a), PHMSA proposes that operators of a distribution system must conduct an evaluation of planned and future installation, modification, or replacement of, or upgrade construction projects and identify any potential for an overpressurization to occur at a district regulator station. Operators must perform this evaluation before performing activities that could result in an overpressurization. PHMSA recognizes that not every construction project performed on a gas distribution system has the same risk profile and not all would require on-site gas monitoring by a qualified employee. However, the pre-construction evaluation must occur regardless to assess the probability of an overpressurization. Some construction projects clearly entail a potential for overpressurization, such as tie-ins and abandonment of distribution pipelines and mains, because work is done while part of the gas system remains active. Similarly, the consequences of overpressurization during construction projects may increase when that work is on low-pressure gas distribution systems where customers do not have

[151] NTSB, Safety Recommendation Report PSR–18–02, ''Natural Gas Distribution System Project Development and Review (Urgent)'' at 6 (Nov. 24, 2018), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PSR1802.pdf.*

[152] This exception will be reflected by addition of new paragraph (d).

secondary pressure regulation at their individual meter.

In paragraph (b), PHMSA proposes that once the evaluation is complete, if an operator has determined that a construction project activity presents a potential for overpressurization, then the operator must ensure that at least one qualified employee or contractor with the capability to shut off the flow of gas is present at that district regulator station to monitor the gas pressure during the construction project activity. This will result in safer construction activities on gas distribution pipelines by requiring operators to ensure that resources have been deployed to effectively mitigate risks the operator had determined exist.

Under this proposal, the employee or contractor must be qualified to monitor the gas pressure in accordance with 49 CFR, part 192, subpart N. Subpart N already requires that operators ensure on-site personnel, such as maintenance crew members and inspectors, are qualified by training and experience to perform covered tasks. Further, subpart N requires that operators qualify these individuals to ensure that covered tasks are conducted in a safe, reliable manner in compliance with regulatory standards. In complying with this new proposal, operators would need to qualify employees and contractors responsible for monitoring the gas pressure during construction to perform various tasks, such as reading and understanding gas monitoring equipment; responding to abnormal operating conditions (*see* § 192.805), including overpressurization indications; shutting off or reducing the pressure to the system; implementing any stop-work authority granted by the operator; and notifying appropriate emergency response personnel should an incident occur. They should also be qualified on the relevant proposed new O&M requirements discussed in subsection IV.D and E.

In paragraph (c), PHMSA proposes to require that, when monitoring the system as described in this section, the qualified personnel should be provided, at a minimum, information regarding the location of all valves necessary for isolating the pipeline system and pressure control records (*see* § 192.638). Providing access to this information could be essential to an employee or contractor performing their gas monitoring responsibilities effectively and help shorten the response time to emergency indications. For example, a qualified employee responsible for monitoring the gas pressure may need to access valves on the system so that they can shut off the flow of gas, isolate the pipeline system, or otherwise mitigate the consequences of an incident. Similarly, a qualified employee responsible for monitoring the gas pressure may need to have more extensive maps of the entire gas system to identify an affected area and detailed information—such as a specific regulator's set point—to determine if a system is operating abnormally. The records proposed in § 192.638 would provide this information and must be accessible to qualified personnel who monitor gas pressure.

Further, under paragraph (c), PHMSA proposes that operators must also ensure that qualified employees monitoring the gas pressure have information regarding emergency response procedures. PHMSA expects such information would include the contact information of the appropriate emergency response personnel. Should field personnel recognize an emergency condition, it is critical for those personnel to have updated emergency contacts and to know what to do and how to respond in an emergency. PHMSA expects operators would already have general emergency contact information in an emergency response plan under § 192.615; however, given that these qualified personnel may be the first to witness overpressurization indications, PHMSA believes it is essential they have immediate access to this information on site during their activities.

Some operators may already provide qualified employees with ''stop-work authority'' to halt work that does not conform to specifications or if they observe unsafe activities on the job site. Although this authority is not required to be given to all qualified employees under proposed § 192.640, it is recommended. Where operators have granted this authority to these qualified personnel monitoring the gas pressure, operators should ensure these employees are trained to recognize unsafe, abnormal conditions that are consistent with an overpressurization.

Overall, the proposals in § 192.640 would reduce the time to respond to an overpressurization by ensuring qualified employees are on site or at an alternative location, and that they are capable of actively monitoring the gas pressure during certain construction project activities. Should an overpressurization occur, these qualified employees would be able to respond (*i.e.,* shutting off or reducing the flow of gas) and thereby mitigate the impact. Under PHMSA's proposal, the qualified employees would be trained to recognize overpressurization indications and be able to respond more quickly. This should mitigate some of the impact of an overpressurization and improve the response time of the operator.

PHMSA also understands that this proposed new requirement would be reasonable, technically feasible, cost-effective, and practicable for gas distribution operators. That operators should evaluate construction projects on their systems to determine whether they could result in an overpressurization at a district regulator station and then ensure that personnel are present who can monitor pressure and prevent such a condition during the work is a common-sense, best practice within industry—whose value was underscored by the Merrick Valley incident and subsequent NTSB recommendation P–18–9. Indeed, PHMSA understands that some operators may already employ compliant maintenance and construction protocols in ordinary course. For other operators, integration of this new requirement within their procedures could be accomplished via supplementation rather than material revisions; the proposed new staffing requirements for construction activity would not require unique skills or equipment to which operators would not have access. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the public safety and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to develop procedures implementing this new regulatory requirement (and manage any related compliance costs).

4. Proposal To Amend § 192.605 Procedures for Qualified Personnel Monitoring Gas Pressure

PHMSA proposes to revise § 192.605, by adding paragraph (b)(13), to ensure gas distribution operators have procedures for implementing the monitoring requirements in the proposed § 192.640. During construction projects on a gas distribution system, qualified personnel may need to perform their monitoring or shutdown activities in a specific sequence. Doing work out of sequence may result in an overpressurization or exacerbate an emergency. For this reason, it is critical to pipeline safety that operators have written procedures for personnel performing the construction activity monitoring requirements proposed in

§ 192.640 to follow. This amendment would ensure that operators must provide qualified personnel with clear procedures for how to perform their responsibilities in a safe manner, and specifically how to monitor for abnormal operating conditions that could lead to an overpressurization.

PHMSA also understands that this proposed new requirement would be reasonable, technically feasible, cost-effective, and practicable for gas distribution operators. As noted above, many operators may already have compliant procedures; those operators lacking such procedures should be able to develop new procedures (or supplement existing procedures) with relatively little difficulty. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments are a cost-effective approach to achieving the public safety and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to develop procedures implementing this new regulatory requirement (and manage any related compliance costs).

H. District Regulator Stations—Protections Against Accidental Overpressurization (Sections 192.195 and 192.741)

1. Background—Overpressure Protection

Gas distribution systems are designed to operate at or below an MAOP. As discussed earlier, a district regulator station is a pressure-reducing facility that receives gas from a high-pressure source (such as a transmission line) and delivers it to a distribution system at a pressure suitable for the demands on the system. An overpressurization occurs when the pressure of the system rises above the set point of the devices controlling its pressure. Pressure regulating and control devices (housed in these district regulator stations) keep the systems' pressure under their MAOP and at or below the desired set point. These devices act as overpressure protection. Because of varying conditions and requirements, there are no standard designs for distribution systems or overpressure protection on such systems. However, among the common approaches to overpressure protection in use today are the following: (1) pressure relief valves, (2) a worker and monitor regulator system, and (3) automatic or remote shutoff (or ''slam-shut'') valves.

Pressure relief valves provide overpressure protection by venting excess gas into the atmosphere and can be used alone or in combination with other methods of overpressure protection. If the relief valve senses that the downstream pressure has exceeded a set point, then the relief valve automatically begins to open to relieve excess gas pressure in the system. If activated, the relief valve protects from overpressurization while allowing gas to flow at a safe pressure, maintaining normal service to customers. In general, the relief valve is a highly reliable device for overpressure protection. Relief valves also provide benefits with respect to alerting or warning operator personnel or the public that an emergency has occurred because (1) these devices are loud if operated at or near a full discharge of excess gas pressure, and (2) the smell of the odorized gas that is vented is also noticeable. However, pressure relief valves entail their own potential public safety harms through their release of gas—which can sometimes ignite—into the atmosphere when activated. Venting of gas to the atmosphere by a relief valve also entails environmental risks: a primary component of natural gas is methane, an ignitable, potent greenhouse gas. For these reasons, section 114 of the PIPES Act of 2020 (codified at 49 U.S.C. 60108(a)(2)(D)(ii)) contains a self-executing requirement for operators of gas distribution pipelines to have a written plan to minimize releases of natural gas—such as by venting from relief valves—from their systems.[153]

A worker and monitor regulator system is a type of pressure control and overpressure protection configuration that involves two pressure reducing valves (*e.g.,* control or pilot valves) installed in a series.[154] One regulator valve controls the pressure of gas to the downstream system. The second regulator valve remains on standby with a slightly higher set point and only begins operating in the event of a malfunction of the first regulator or another failure results in pressure exceeding the set point of the first regulator. If the first, primary regulator (the ''worker'' regulator) cannot control the pressure, the second regulator (the ''monitor''), which senses the rising downstream pressure, automatically begins to operate to maintain the pressure downstream at a gas pressure slightly higher than normal, albeit still within safe operation. Sometimes an operator will also install a small relief valve downstream to act as a ''token relief'' or an alarm to alert the operator that the regulator has failed.

When working properly, a worker and monitor regulator system should not interrupt service if an overpressurization occurs. An advantage of the worker and monitor regulator system is that it does not result in venting large volumes of gas to the atmosphere, thereby reducing public safety and environmental harms. Unlike with pressure relief valves, the pressure reducing valves used in the worker and monitor regulator system described above are not self-operated; instead, control lines are installed in this type of system. Control lines (often called ''sensing'' or ''impulse'' lines) are small-diameter pipes that transmit the signal pressure from the tie-in point on the downstream piping line to the pressure regulating device. When the downstream pressure decreases, the regulator opens wider to allow more gas to flow. The regulator valve remains open until it senses an increase in pressure or the demand of the downstream pressure has been met. Control lines must be protected against breakage because the regulator will open wide if the control lines are cut or damaged because the regulator will not detect that the demand has been met, it will remain open, allowing gas to flow freely. This could result in full upstream pressure being forced into the low-pressure system, resulting in a catastrophic situation as seen in the Merrimack Valley incident.

A third type of overpressure protection is automatic shutoff devices. In the event of an overpressurization indication or event, an automatic shutoff device completely shuts off the gas flow to the system until the operator determines the cause of the malfunction and resets the device. In many cases, an automatic shutoff device is used as a secondary form of overpressure protection.

2. Current Requirements—Overpressure Protection

Section 192.195 describes the minimum requirements for protection against accidental overpressurization. Section 192.195(a) requires that ''each pipeline that is connected to a gas

[153] *See* ''Pipeline Safety: Statutory Mandate to Update Inspection and Maintenance Plans to Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas from Pipeline Facilities,'' ADB–2021–01, 86 FR 31002 (June 10, 2021).

[154] There are a few types of monitor regulating, all of which operate substantially similarly as described herein: working monitor, series regulation, and relief monitoring.

source so that the [MAOP] could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§ 192.199 and 192.201.'' [155] Section 192.195(b) adds that ''[e]ach distribution system that is supplied from a source of gas that is at a higher pressure than the [MAOP] for the system must—(1) [h]ave pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and (2) [b]e designed so as to prevent accidental overpressuring.'' This pipeline safety regulation has existed in 49 CFR part 192 since its inception.[156]

Section 192.199 describes the minimum requirements for the design of pressure relief and limiting devices. Section 192.199(g) states that ''[w]here installed at a district regulator station to protect a pipeline system from overpressuring, [the pressure relief or pressure-limiting device must] be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator[.]''

Section 192.201 describes the minimum requirements for the required capacity of pressure-relieving and -limiting stations. Section 192.201(a)(1) requires that ''[i]n a low-pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.'' Section 192.201(c) requires that ''[r]elief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.'' Section 192.203(b)(9) adds that ''[e]ach control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.'' PHMSA has clarified through its enforcement guidance that an occurrence of overpressurization may be indicative of an equipment failure or design flaw.[157]

In addition, § 192.739 describes the minimum requirements for the inspection and testing of pressure-limiting and regulating stations. Section 192.739 requires annual inspection and testing of each pressure limiting or regulating stations, including relief devices. The inspection and tests should determine that the station is: (1) in good mechanical condition; (2) adequate from the standpoint of capacity and reliability of operation for the service in which it is employed; (3) except as provided in § 192.739(b) applicable to certain steel pipelines, set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201(a); and (4) properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation. These requirements are intended to address inspection and testing of pressure-limiting and regulator stations necessary to maintain safe pressures on the gas distribution system.

Section 192.741 describes minimum requirements for the telemetering or recording gauges on pressure-limiting and regulating stations. Section 192.741(a) states that ''[e]ach distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district.'' Section 192.741(b) requires that, ''[o]n distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.''

3. Need for Change—Overpressure Protection

The pipeline safety regulations governing overpressure protection of low-pressure distribution systems have not changed since their inception in the 1970s. For years, low-pressure gas distribution systems, like CMA's system in the Merrimack Valley, have relied on overpressure protection systems like the redundant worker and monitor regulators to regulate and control the pressure and flow of gas. While these overpressure protection methods are safe under normal operating conditions, this method of overpressure protection on low-pressure distribution systems can be too easily defeated, as recent events with a common mode of failure have demonstrated. PHMSA's proposed change to regulations governing overpressure protection is intended to facilitate the operation of gas distribution systems to avoid catastrophic overpressurization.

According to the NTSB's report, the low-pressure system in Merrimack Valley met the requirements for overpressure protection contained in § 192.195 (Protection Against Accidental Overpressuring) and § 192.197 (Control of the Pressure of Gas Delivered from High-pressure Distribution Systems). ''At each of the 14 regulator stations feeding natural gas into [CMA's] low-pressure system, there were two regulators [(*i.e.,* a worker and monitor regulator system)] installed in a series to control the natural gas flow from the high-pressure [. . .] system.'' [158] The worker regulator and the monitor regulator were set to limit the pressure to a maximum safe value to the customer. But the system nonetheless failed. After reviewing accidents investigated by the NTSB over the past 50 years, as well as prior NiSource incidents, the NTSB found that this scheme for overpressure protection can be defeated by a common mode of failure, like operator error or equipment failure.[159]

CMA's overpressurization was not an isolated event. For example, on January 28, 1982, in Centralia, MO, high-pressure natural gas entered a low-pressure natural gas distribution system after a backhoe damaged the regulator control line at the Missouri Power and Light Company's district regulator station.[160] Because the regulator no longer sensed system pressure, the regulator opened, and high-pressure natural gas entered customer piping systems. In some cases, this resulted in high pilot-light flames that ignited fires in buildings. In other cases, the pilot-light flames were blown out, allowing natural gas to escape within the buildings. Of the 167 buildings affected by the overpressurization, 12 were destroyed and 32 sustained moderate to heavy damage. Five occupants suffered minor injuries.

The NTSB investigated one other incident in 1977 that was nearly identical to the 2018 incident in

[155] Except as provided in § 192.197, which only applies to high-pressure gas distribution systems.

[156] *See* ''Establishment of Minimum Standards,'' 35 FR 13248, 13264 (Aug. 19, 1970).

[157] PHMSA, ''Operations & Maintenance Enforcement Guidance Part 192 Subparts L and M'' at 149 (July 21, 2017), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/regulatory-compliance/pipeline/enforcement/5776/o-m-enforcement-guidance-part-192-7-21-2017.pdf.*

[158] NTSB/PAR–19/02 at 39.

[159] NTSB/PAR–19/02 at 39–40.

[160] NTSB, Accident Report PAR–82/03, ''Missouri Power and Light Company Natural Gas Fires, Centralia, Missouri, January 28, 1982'' (Aug. 24, 1982).

Merrimack Valley. Both incidents occurred when a cast-iron main with control lines attached was isolated as part of a pipe replacement project. On August 9, 1977, natural gas under high pressure entered a Southern Union Gas Company's low-pressure natural gas distribution pipeline and overpressurized a system serving more than 750 customers in a 7-block area in El Paso, TX. The gas company was replacing a section of 10-inch cast-iron low-pressure natural gas main containing the pressure-sensing control lines for a nearby upstream regulator station and its monitor and isolated it between two valves with a temporary bypass installed. Southern Union Gas Company was aware that the isolated section contained the control lines but did not realize the potential hazard of isolating the pressure-sensing control lines, which would make the two regulators inoperative. Without the ability to sense the actual pressure in the gas main, the regulators allowed the pressure to build up and overpressurized the rest of the affected system. The problem was corrected before causing any fatalities or major injuries.[161]

As a result of its investigation of the CMA overpressurization event, as well as a review of multiple overpressurizations that occurred as the result of a common mode of failure, the NTSB recommended in P–19–14 that PHMSA revise 49 CFR part 192 to require additional overpressure protection for low-pressure natural gas distribution systems that cannot be defeated by a single operator error or equipment failure. NiSource also took action to remove this vulnerable design on their systems. On December 14, 2018, the CEO of NiSource committed to the NTSB that they would install automatic pressure control equipment, referred to as ''slam-shut'' devices, on every low-pressure system throughout their operating area.[162] These devices provide another level of control and protection, as they immediately shut off gas to the system when they sense operating pressure that is too high or too low. That measure exceeds current Federal requirements.

Subsequent to the 2018 CMA incident, PHMSA was required by statute to issue regulations ensuring that distribution system operators minimize the risk of a common mode of failure at low-pressure district regulator stations, monitor the gas pressure of a low-pressure system, and install overpressure protection safety technology at low-pressure district regulator stations. (49 U.S.C. 60102(t)(3)). The mandate also provides that if it is not operationally possible to install such technology, PHMSA's regulations must provide that operators would have to develop and follow plans that would minimize the risk of an overpressurization.

After reviewing NTSB's recommendations, the CMA and other related incidents, and the requirements of 49 U.S.C. 60102(t)(3), PHMSA proposes additional requirements to improve the design standard for overpressure protection on low-pressure distribution systems. Gas distribution systems that use only regulators and control lines as the means to prevent overpressurization are not sufficient protection from overpressurization events. Therefore, PHMSA is proposing additional layers of protection specific to low-pressure distribution systems to set a safer design standard for these systems.

4. Proposal To Amend § 192.195—Overpressure Protection

Consistent with 49 U.S.C. 60102(t)(3), PHMSA proposes to amend § 192.195 to impose three additional requirements for each district regulator station that serves a low-pressure distribution system. First, each district regulator station must consist of at least two methods of overpressure protection (such as a relief valve, monitoring regulator, or automatic shutoff valve) appropriate for the configuration and location of the station. Under this proposal, operators have options for meeting the new requirements for overpressure protection. For example, one option is for operators of low-pressure distribution systems to install a full relief valve downstream of existing overpressure protections. Another option is to install an automatic shutoff valve. In that case, for operators with the worker and monitor regulator set up, the addition of an automatic shutoff valve downstream of the existing setup would stop the flow of gas if an overpressurization occurred and both regulators failed. Further, some automatic shutoff valves have the capability to activate if the system experiences an underpressurization.[163] PHMSA discussed these additional options in the overpressure protection advisory bulletin (ADB–2020–02), but there are other configurations that would be suitable as well.

PHMSA proposes this two-method requirement as mandatory for district regulator stations that are new, replaced, relocated, or otherwise changed after the effective date of the final rule. For all other systems, PHMSA proposes to amend § 192.1007(d)(2)(ii) to require operators to ensure district regulator stations have two methods of overpressure protection consistent with proposed § 192.195(c)(1), or identify and notify PHMSA of alternative preventive and mitigative measures. PHMSA finds that this approach meets the mandate found at 49 U.S.C. 60102(t)(3)(iii) and (iv) for all district regulator stations to have at least two methods of overpressure protection technology appropriate for the configuration and siting of the station, while allowing for alternate action where PHMSA determines it is not operationally possible to have such secondary relief. PHMSA concludes that it is operationally possible for operators to include at least two methods of overpressure protection in new, replaced, relocated, or otherwise changed district regulator stations. And, for existing district regulator stations, PHMSA recognizes that there may be unique cases where it is not operationally possible to have a second measure, in which circumstance an operator may notify PHMSA under § 192.1007(d)(2)(ii)(B) of the alternative measures to minimize the risk of an overpressure event.

Second, PHMSA proposes that each district regulator station that services a low-pressure system must minimize the risk of overpressurization that could be caused by any single event (such as excavation damage, natural forces, equipment failure, or incorrect operations) that either immediately or over time affects the safe operation of more than one overpressure protection device. PHMSA notes that 49 U.S.C. 60102(t)(3) requires the promulgation of regulations that minimize the risk of gas pressure exceeding the MAOP from a common mode of failure. PHMSA interprets the statutory term ''common mode of failure'' to mean a failure where a single common cause could immediately or over time cause multiple failures that result in an overpressurization on a downstream distribution system. PHMSA's interpretation of ''common mode of failure'' is intended to ensure that operators are identifying as many potential failure modes in their systems as possible.

[161] NTSB, Safety Recommendation(s) P–77–43 (Dec. 9, 1977), *https://www.ntsb.gov/safety/safety-recs/RecLetters/P77_43.pdf.*

[162] Sec. and Exch. Comm'n, Form 10–Q Quarterly Report, ''NiSource, Inc.'' at 42 (Oct. 30, 2019), *https://www.sec.gov/Archives/edgar/data/1111711/000111171119000041/ni-2019930x10q.htm.*

[163] An underpressurization could occur if there is a pipeline rupture downstream, which is a risk during excavation.

This practice of identifying potential common modes of failure will be particularly important for operators of low-pressure gas distribution systems, whose designs make them more vulnerable to overpressurization. For example, hydrotesting upstream of the district regulator station could cause moisture to be injected into the gas system, which then could cause the working and monitor regulators to freeze up before the gas distribution operator responds. Construction work upstream of the district regulator station could cause contaminants like metal shavings to be introduced into the gas system, which then could damage the working and monitor regulator diaphragms before the gas distribution operator could respond. Oil, hydrates, or high sulfides that enter the gas system could affect both the working and monitoring regulators before the gas distribution operator could respond. A contractor or third party could damage both downstream control lines at the same time. And, as seen in the 2018 Merrimack Valley incident, connecting a new main to the district regulator station without connecting the control lines to the new piping could result in an overpressurization. In its proposed § 192.195(c)(2), PHMSA provides examples of single events that could cause a common mode of failure, such as excavation damage, natural forces, equipment failure, or incorrect operations. While operators are best positioned to identify other scenarios that could introduce a common mode of failure on their unique gas distribution systems, applying any of the design standards described in this proposed amendment could eliminate most of the common modes of failure described in this paragraph and in § 192.195(c)(2) by providing additional redundancy in the gas distribution system.

Third, pursuant to 49 U.S.C. 61012(t)(3), PHMSA proposes in § 192.195(c)(3) to require that low-pressure distribution systems have remote monitoring of gas pressure at or near the location of overpressure protection devices. Remote monitoring in this context means that the device is capable of monitoring the gas pressure near the location of overpressure protection devices and remotely displaying the gas pressure to operator personnel in real time. Low-pressure gas distribution operators are already required to have devices such as telemetering or recording gauges that record gas pressure (see §§ 192.199 and 192.201). However, the current telemetering and recording device requirements in § 192.741 do not require active monitoring and some of these devices employed under §§ 192.199, 192.201, and 192.741 are not designed to provide real-time awareness or notification of potential overpressurizations. Installing these real-time monitoring devices will improve an operator's ability to receive timely overpressurization indications, thereby giving operator personnel an opportunity to avoid or mitigate adverse consequences. Accordingly, PHMSA also proposes a conforming change in a new § 192.741(d) to specify that operators of low-pressure distribution systems that are new, replaced, relocated, or otherwise changed beginning one year after the publication of any final rule in this proceeding must monitor the gas pressure in accordance with § 192.195(c)(3).

These three new design standards would be applicable to low-pressure distribution systems that are new, replaced, relocated, or otherwise changed beginning one year after the publication of any final rule in this proceeding. A modification to either the low-pressure system or the district regulator station made on or after the compliance date above would require an operator to meet the proposed new design standards described in this section. For example, as operators upgrade their low-pressure systems as part of the cast iron replacement program or implement mitigating measures to address the risk of overpressurization through the DIMP requirements in § 192.1007, they would be required to ensure those upgrades meet the proposed design standard in § 192.195(c). PHMSA would not expect operators performing routine maintenance to upgrade their systems to meet the proposed design standard.

PHMSA understands this proposed requirement for gas distribution operators to incorporate in their design of low-pressure distribution systems the overpressure protection measures described above would be reasonable, technically feasible, cost-effective, and practicable. These proposed enhanced design and installation requirements would be applicable only to certain gas distribution operators—those with district regulators serving low-pressure systems—and then only when components within their systems are new, replaced, relocated, or otherwise changed. Affected operators would therefore be able to integrate these common-sense, proposed safety enhancements within larger construction, installation, and replacement projects. Indeed, some low-pressure gas distribution system operators may already be complying with this proposed requirement either as a voluntarily for commercial reasons (to minimize the loss of a valuable commodity), as a safety practice (implementing lessons learned from the Merrimack Valley incident and NTSB recommendation P–19–14) or as a mitigation measure pursuant to their DIMP. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to incorporate these requirements in plans for new, replaced, relocated, or otherwise changed low pressure distribution systems (and manage any related compliance costs).

I. Inspection: General (Section 192.305)

1. Current Requirements—Inspections

Section 192.305 (Inspection: General) states that ''[e]ach transmission line or main must be inspected to ensure that it is constructed in accordance with this part.''

2. Need for Change—Inspections

On November 29, 2011, PHMSA issued an NPRM that included a proposal to modify the requirements contained in § 192.305 to specify that a gas transmission pipeline or distribution main cannot be inspected by someone who participated in its construction.[164] This addressed concerns expressed by State and Federal regulators and was based in part on a 2011 NAPSR resolution calling for revisions to § 192.305 to provide that contractors who install a transmission pipeline or distribution main should be prohibited from inspecting their own work for compliance purposes.[165] At the time, § 192.305 had simply provided that each transmission pipeline or distribution main must be inspected to ensure that it was constructed in accordance with 49 CFR part 192. In a final rule issued on March 11, 2015, PHMSA amended § 192.305 to specify that a pipeline operator may not use the same operator personnel to perform a required

[164] ''Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations,'' 76 FR 73570 (Nov. 29, 2011). On July 11, 2012, the Gas Pipeline Advisory Committee (GPAC) recommended that PHMSA adopt this amendment.

[165] NAPSR, Resolution CR–1–02, Doc. No. PHMSA–2010–0026–0002 (Dec. 15, 2011).

inspection who also performed the construction task that required inspection.[166]

PHMSA received petitions for reconsideration of various elements of the March 2015 final rule, including petitions from the American Public Gas Association (APGA) and other stakeholders raising concern about the construction inspection requirement in § 192.305 for smaller operators for whom it may be particularly difficult to have different personnel perform construction and inspection activities.[167] The APGA petition noted that utilities with only one qualified crew who work together to construct distribution mains would not have anyone working for the utility available and qualified to perform the inspection under the amended language, which could significantly increase the costs for those utilities by requiring small utilities to contract with third parties for such inspections.[168] In 2015, according to the APGA, 585 municipal gas utilities had 5 or fewer employees. The APGA stated that its concerns would be alleviated by a clarification stating a two-man utility crew may inspect each other's work and comply with the amendment to § 192.305.

NAPSR, on the other hand, submitted a petition criticizing the March 2015 final rule for not limiting the § 192.305 prohibition to contractor personnel inspecting the work performed by their own company's crews, contending that such an approach would not resolve the potential conflict of interest that had been the occasion for its 2011 resolution.[169] NAPSR added that prohibition should not apply to an operator's own construction personnel as NAPSR believed they would have less of an incentive to accept poor quality work when conducting an inspection than a contractor inspecting his colleagues' work. NAPSR asked for a delay in the effective date of the final rule relative to § 192.305 until PHMSA had reviewed the rule and worked with NAPSR to address its concerns.

PHMSA responded to the petitions for reconsideration of the March 2015 final rule on September 30, 2015, and, in recognition of the concerns expressed, indefinitely delayed the effective date of the § 192.305 amendment.[170] Because other proposed amendments in this NPRM may impact the number of inspections and construction activities on gas distribution mains, PHMSA believes it is appropriate to re-examine this issue.

3. Proposal To Amend § 192.305—Inspections

In this NPRM, PHMSA proposes to remove the existing suspension of § 192.305, relocate the existing regulatory language adopted in the March 2015 final rule to a new paragraph (a), and add a new paragraph (b) addressing concerns raised in APGA's petition for reconsideration pertaining to the potential impact on small operators.

If adopted, PHMSA's proposed § 192.305(a) would require each gas transmission pipeline (along with each offshore gas gathering, and Types A, B, and C gathering pipelines pursuant to § 192.9) and distribution main that is newly installed, replaced, relocated, or otherwise changed beginning one year after the publication of a final rule to be inspected to ensure that it is constructed in accordance with the requirements of this subpart, using different personnel to conduct the inspection than had performed the construction activity. This requirement—which would lift the suspension of the regulatory amendments adopted in the March 2015 final rule—was the subject of extensive consideration in PHMSA's earlier notice and comment rulemaking (including during a meeting of the Gas Pipeline Advisory Committee (GPAC)).[171]

PHMSA understands that the public safety and environmental risks associated with releases from Type C gathering pipelines, a category created in a final rule issued in November 2021[172] and thus not included in the 2015 assessment of cost-effectiveness, technical feasibility, and practicability, are similar to the risks associated with other part 192-regulated gas gathering pipelines (which generally transport unprocessed natural gas containing higher percentages of volatile organic compounds, corrosives, and hazardous airborne pollutants than processed natural gas transported in other pipelines). PHMSA therefore proposes to subject Type C gathering pipelines to the inspection requirements at § 192.305(a). PHMSA expects to have operator-reported data after the reporting cycle completes in spring of 2023 for these newly regulated gathering lines.[173] To address this uncertainty, PHMSA estimates that most Type C lines are operated by operators of other part 192-regulated gathering pipelines such that they are already included in the 2015 assessment of this regulatory requirement for other lines.[174] PHMSA explains this estimate in greater length in the associated preliminary regulatory impact analysis.

Additionally, PHMSA has evaluated concerns raised in APGA and other petitioners' reconsideration petitions, and PHMSA proposes to add a paragraph (b) that would provide an exception to the construction inspection requirement for gas distribution mains for small gas distribution operators for whom complying with paragraph (a) may prove difficult due to their limited staffing. Specifically, PHMSA proposes to allow operator personnel involved in the same construction task to inspect each other's work on mains when the operator could otherwise comply with the construction inspection requirement in paragraph (a) of this section only by using a third-party inspector. This justification must be documented and retained for the life of the pipeline. This exception is in acknowledgment that, as highlighted by APGA, there are times when only one or two people are available to perform a task and the current requirements may be overly burdensome for smaller gas distribution operators. PHMSA proposes to limit this exception to distribution operators because it understands that: (1) many of these operators are likely to have a limited number of employees, thereby necessitating reliance on contractor personnel; and (2) the public safety risks from delays in undertaking safety-improving construction projects

[166] "Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations," 80 FR 12762, 12779 (Mar. 11, 2015).

[167] APGA, "Petition for Clarification or in the Alternative Reconsideration of the American Public Gas Association," Doc. No. PHMSA–2010–0026–0055, at 4 (Apr. 10, 2015); American Gas Association, "Request for Effective Date Extension for Construction Inspection Changes and Petition for Reconsideration of 'Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations," Doc. No. PHMSA–2010–0026–0056 (Apr. 10, 2015); NAPSR, "NAPSR Request for Delay in the Effective Date of Amended Rule 192.305 on Construction Inspection," Doc. No. PHMSA–2010–0026–0059 (July 28, 2015).

[168] APGA, "Petition for Clarification or in the Alternative Reconsideration of the American Public Gas Association," Doc. No. PHMSA–2010–0026–0055, at 4 (Apr. 10, 2015).

[169] NAPSR, "NAPSR Request for Delay in the Effective Date of Amended Rule 192.305 on Construction Inspection," Doc. No. PHMSA–2010–0026–0059 (July 28, 2015).

[170] "Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations: Response to Petitions for Reconsideration," 80 FR 58633, 58634 (Sept. 30, 2015).

[171] PHMSA incorporates by reference in this proceeding pertinent materials from the administrative record in the earlier proceeding. Those materials can be found in Doc. No. PHMSA–2010–0026.

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

[173] PHMSA's preliminary review of the incoming reported data supports its estimates in the PRIA for Type C lines.

[174] *See* Preliminary Regulatory Impact Analysis, available in the docket for this rulemaking.

(because of a lack of qualified inspection personnel) on these pipelines would be particularly compelling given their (typical) location near or within population centers. PHMSA believes this proposed amendment addresses concerns raised in APGA's petitions for reconsideration regarding the unintended burdens of the March 2015 rulemaking on small operators.

PHMSA acknowledges that NAPSR, in its 2011 resolution and petition for reconsideration of the March 2015 final rule, called for limiting the prohibition to contractor personnel inspecting the work of their own crew, as NAPSR does not view an ''inherent conflict of interest'' arising from operator-employed personnel doing the same.[175] PHMSA agrees with NAPSR that a lack of independence in inspection activity raises public safety concerns but disagrees that there is a material distinction in risk between those personnel directly employed by the operator and those third-party personnel contracted by the operator. Further, creating such a distinction could diminish the scope of the safety benefit while placing burden on smaller operators who rely on contractors for a large portion of their construction work. Therefore, PHMSA does not see a reasoned basis to discriminate between operator personnel and contracted personnel for the purposes of this inspection.

PHMSA understands this proposed amendment to restore a previously approved (but now suspended) requirement that post-construction inspections be performed by personnel other than those who performed the construction work being inspected would be reasonable, technically feasible, cost-effective, and practicable for all affected operators. That requirement reflects the proposition—reflected in industry best practice—that an independent second set of eyes inspecting a construction project provides more robust assurance of work product quality than allowing construction personnel to inspect their own work. Although PHMSA acknowledges that this proposed requirement could entail additional compliance burdens (in terms of costs and stretching limited personnel resources) for some operators, PHMSA believes those burdens would be manageable because (1) all operators could account for them at the project planning phase in a way that allows them to control costs or secure requisite supplemental personnel (or contractors), and (2) small gas distribution system operators whose limited personnel resources would make them dependent on (potentially expensive) contractors would be excepted from this requirement. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their procedures and obtain access to inspection personnel for near-term installation projects (as well as manage any resulting compliance costs).

J. Records: Tests (Sections 192.517 and 192.725)

1. Current Requirements—Records: Tests

Section 192.517(b) applies to all gas pipeline operators and states that ''[e]ach operator must maintain a record of each test required by §§ 192.509 [pipelines operating below 100 psig], 192.511 [service lines], and 192.513 [plastic pipelines], respectively, for at least 5 years.'' Section 192.725(a) states that ''each disconnected service line must be tested in the same manner as a new service line, before being reinstated.''[176]

2. Need for Change—Records: Tests

On October 7, 2021, NAPSR submitted a resolution seeking that PHMSA amend § 192.517(b) in several ways. NAPSR recommended PHMSA amend its regulations to require operators to retain test documentation under § 192.517(b) for the life of the corresponding pipeline segment as opposed to the current 5 years.[177] The resolution also requested that PHMSA require operators to retain for the life of the pipeline ''the test pressure documentation created within the five years prior'' to any such amendment. Additionally, NAPSR requested that PHMSA require additional, more detailed, information be documented as part of these test records. PHMSA agrees that the detailed recordkeeping content and retention requirements suggested by NAPSR will improve consistency and promote public safety and protection of the environment.

NAPSR also requested that PHMSA add § 192.725 (''Test requirements for reinstating service lines'') to the list of required test records in § 192.517(b). It reasoned that § 192.603(b), which requires operators to keep records necessary to administer the procedures established under § 192.605, is potentially in conflict with § 192.517. PHMSA clarifies that the requirement in § 192.725 to perform a test ''in the same manner as a new service line'' is meant to direct an operator to conduct a test required for a new service line in accordance with 49 CFR part 192, subpart J. A test performed to meet § 192.725 does not constitute a new type of test for purposes of identifying recordkeeping requirements for such a test. PHMSA expects an operator to select the appropriate test in subpart J to meet the testing requirement of § 192.725, which includes meeting the corresponding recordkeeping requirements of § 192.517. For that reason, PHMSA does not propose to include § 192.725 in the list of tests identified within § 192.517.

3. Proposal To Amend § 192.517—Records: Tests

PHMSA proposes to amend § 192.517 to require that records of tests covered by § 192.517(b) (*i.e.,* tests performed according to § 192.509, 192.511, and 192.513) be retained for the life of the pipeline. This amendment would be applicable to all gas pipeline operators. PHMSA would require operators to retain the records for all tests presently being retained under the existing language of § 192.517(b) from the preceding five years, which under the proposal would then be retained for the life of the pipeline. PHMSA also proposes to require that the records of these tests include, at a minimum, sufficient information to document the test, including information about the

[175] *See* NAPSR, Res. 2015–01, ''A Resolution Seeking Suspension of the Effective Date of a Recently Adopted Federal Final Rule, and Reconsideration of that Rule,'' at 2 (Sept. 3, 2015), *https://www.napsr.org/resolutions.html.*

[176] Paragraph (b) provides an exception to paragraph (a) for any part of the original service line used to maintain continuous service during testing if provisions are made to maintain continuous service.

[177] NAPSR, Res. 2021–02, ''A Resolution Seeking a Modification of 49 CFR 192.517(b) to Require Certain Distribution Pipeline Pressure Test Information Be Documented and to Require the Retention of Test Documentation for Distribution Pipelines for the Lifetime of the Corresponding Pipeline Segment,'' Doc. No. PHMSA–2021–0046–0005 (Oct. 7, 2021). This extended retention period would include records of tests establishing an MAOP, as NAPSR explains in its petition: ''PHMSA has set forth regulations requiring the availability and use of pipeline pressure documentation to establish the maximum allowable operating pressure (MAOP) of pipelines, including short segments of replaced or relocated pipe, prior to placing them in service within Subpart L of 49 CFR 192, specifically 49 CFR 192.619.''

operator, the individual or any company used to perform the test, pipeline segment being tested, test date, medium, pressure, duration, and any leaks or failures noted and their disposition. Retaining tests for the life of the pipeline, instead of the current retention period of 5 years, ensures that records are available whenever repairs are necessary, or should an incident occur, records are available to support an operator's inspection and investigation into the root cause of a failure. Further, PHMSA currently requires (per § 192.603(b) and § 192.605) operators to keep MAOP records for life of facility but MAOP records established by § 192.517(b) tests are just 5 years. PHMSA believes that these changes will improve the quality and availability of test records, including records of leaks occurring during testing activities and MAOP establishment records.

PHMSA understands this proposed amendment of an existing record retention requirement to be reasonable, technically feasible, cost-effective, and practicable. The proposed changes are incremental supplementation of current requirements regarding recording and retaining record of pressure tests operators are already required to conduct. The proposed amendments require operators to document information they may already be obtaining through the required tests under this current requirement, more clearly states that information which operators should record from the tests and extends the retention period; PHMSA expects some operators may already be in their substantial compliance with this proposed requirement. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their procedures to ensure identification or generation of pertinent records (and manage any related compliance costs).

4. Proposal To Amend § 192.725—Test Requirements for Reinstating Service Lines

PHMSA proposes to revise § 192.725 to clarify that ''tested in the same manner as a new service line'' in the existing regulation means ''tested in accordance with subpart J of this part'', by inserting that clarifying language within a parenthetical. PHMSA understands that this proposed revision merely clarifies an existing requirement and is therefore technically feasible and practicable. PHMSA further notes that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement updates, if any are needed, to their procedures.

K. Miscellaneous Amendments Pertaining to Part 192—Regulated Gas Gathering Pipelines (Sections 192.3 and 192.9)

1. Current Requirements—Gas Gathering

Among the regulatory amendments adopted in the April 2022 Valve Rule were enhanced emergency planning and notification requirements applicable to all part 192-regulated gas pipeline operators subject to § 192.615, to include new references to public safety answering points (such as 9–1–1 call centers) and a requirement for those operators to update their written procedures to provide for timely rupture identification; certain new, implementing definitions at § 192.3 applicable to all part 192-regulated gas pipelines; and within a new § 192.635, a definition of the term ''notification of potential rupture'' applicable to those part 192-regulated pipelines subject to that provision.

The D.C. Circuit, however, vacated those new requirements as to gas gathering pipelines in a decision issued in May 2023.[178] PHMSA subsequently issued a Technical Correction codifying the court's decision by introducing exceptions to the above provisions restricting their application to the part-192 regulated gas gathering pipelines to which they had applied.[179] Specifically, the Technical Correction introduced language in each of the § 192.3 definitions adopted in the Valve Rule (''entirely replaced onshore transmission pipeline segments''; ''notification of potential rupture''; and ''rupture-mitigation valve (RMV)'') excepting all part 192-regulated gas gathering pipelines from those definitions. The Technical Correction also introduced a series of exceptions within the regulatory cross-reference provision at § 192.9 preventing application of the Valve Rule's amendments at §§ 192.615 and 192.635 regarding emergency response and notification and rupture identification procedures to each of offshore gas gathering pipelines (§ 192.9(b)) as well as onshore Types A (§ 192.9(c)) and C (§ 192.9(e)) gas gathering pipelines.

2. Need for Change—Gas Gathering

Written emergency planning and notification procedures are critical tools for the safe operation of any gas pipeline. Offshore, Type A, and Type C gas gathering pipelines had—consistent with the risks to public safety and the environment posed by an emergency involving those high-pressure, gas pipeline facilities[180]—been subject to extensive emergency planning and notification requirements before issuance of the Valve Rule in April 2022. Those long-standing safety standards include requirements for operators to have written emergency procedures for notifying, establishing, and maintaining communications with fire, police, and other public officials (§ 192.615(a)(2) and (8); § 192.615(c)); taking actions necessary to minimize hazards to public safety from the emergency (§ 192.615(a)(6)); and directing operator control room response actions in an emergency (§ 192.615(a)(11)).

The amendments to § 192.615 introduced in the Valve Rule were modest refinements to those long-standing emergencies response planning and notification requirements. The Valve Rule explained its amendments to § 192.615(a)(2), (a)(8), and (c) adding language requiring notification of, and communication with, public safety answering points (PSAPs) or emergency coordination agencies ensure notifications of pipeline emergencies are channeled to resources best positioned to alert first responders and coordinate response efforts across multiple jurisdictions that may be affected by a pipeline emergency.[181] The Valve Rule also made a pair of incremental changes to § 192.615(a)(6)'s requirement that operator procedures provide for taking certain actions—emergency shutdown or pressure reduction—to minimize public safety risks. The first change was to add language (''including, but not limited to . . .'') clarifying that operator procedures could provide for actions

[178] *GPA Midstream Assn.* v. *Dep't of Transp.,* 67 F.4th 1188, 1201 (D.C. Cir. 2023).

[179] 88 FR at 50058, 50060–61 (Aug. 1, 2023).

[180] *See, e.g.,* ''Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards—Final Rule,'' 71 FR 13292, 13296–97 (Mar. 15, 2006) (discussing safety basis for broadly extending part 192 requirements for gas transmission lines to Type A gas gathering pipelines); 86 FR at 63284–85 (discussing safety basis for extending § 192.615 requirements to high-pressure, large-diameter Type C gas gathering pipelines).

[181] 87 FR at 20969–70, 20973.

other than system shutdown or pressure reduction in an emergency, thereby granting operators greater flexibility in designing response actions best capable of minimizing hazards in a pipeline emergency; this includes the additionally enumerated action of valve shut-off. The second change included a reference to environmental hazards. Among those hazards operator procedures must minimize, reflecting the fact that the mechanism for public safety and environmental harms (namely, the release of gas from a pipeline) is identical.

The Valve Rule also made several regulatory amendments to address the time-dependent [182] risks to public safety and the environment posed by ruptures on gas pipelines. First, the Valve Rule added at § 192.3 (which in turn references a new § 192.935) the new term ''notification of potential rupture'' codifying commonly-understood indicia of a rupture.[183] The Valve Rule also added a pair of requirements ensuring timely identification of, and response to, this particular emergency in which every second lost can increase public safety and environmental consequences: a new § 192.615(a)(12) requiring operators develop procedures for confirming actual ruptures following reports of the indicia listed in the new definition of ''notification of potential rupture'', as well as language at § 192.615(a)(8) introducing a new requirement for immediate and direct notification of PSAPs on an operator's notification of a potential rupture.[184] Similarly, PHMSA enhanced a longstanding requirement at § 192.615(a)(11) governing emergency procedures for control room personnel by adding a cross-reference to newly-adopted provisions pertaining to rupture mitigation valves at §§ 192.634 and 192.636.

Lastly, the Valve Rule adopted certain other definitions of terms (''entirely replaced onshore transmission segment''; and ''rupture-mitigation valve'') employed in its regulatory amendments.

3. Proposal To Amend §§ 192.3 and 192.9—Emergency Procedures and Notification; Rupture Identification Procedures

PHMSA proposes several amendments to restore certain emergency planning, notification, and rupture identification procedures vacated by the D.C. Circuit with respect to gas gathering pipelines. First, PHMSA proposes to delete from each of the § 192.3 definitions introduced in the Technical Correction language disclaiming application of those terms to any part 192-regulated gas gathering line.[185] Second, PHMSA proposes to delete from § 192.9 similar language excluding application of the Valve Rule's amendments to § 192.615 discussed in section IV.K.2 above to offshore gas gathering (§ 192.9(b)), Type A (§ 192.9(c)), and Type C (§ 192.9(e)) gas gathering lines. This proposal is focused on application of these emergency response provisions to gathering lines; PHMSA is not, however, proposing in this rulemaking to restore application to part 192-regulated gas gathering lines of other regulatory amendments adopted in the Valve Rule pertaining to rupture mitigation valve installation, operation, and maintenance.

As explained in section IV.K.2 above, the Valve Rule's amendments to § 192.615 are incremental improvements on existing requirements applicable to offshore, Type A, and Type C gas gathering pipelines. Some of those amendments are broad in scope and are applicable to any emergency on those gas gathering pipelines; others are specific to ruptures on those pipelines. And each of those amendments is a common-sense, baseline expectation ensuring operator emergency planning and notification procedures are directed toward timely and effective response and mitigation of risks to public safety and the environment.

PHMSA understands these proposed amendments would be reasonable, technically feasible, cost-effective and practicable for affected gas gathering pipeline operators. The restoration of definitions at § 192.3 are not themselves operative provisions entailing compliance burdens for operators; several of those definitions, moreover, are used in operative provisions inapplicable to gas gathering pipelines. And although the restored applicability of the Valve Rule's revisions to § 192.615 could entail additional compliance burdens for affected gas gathering operators, some operators may already incorporate the required content in their pipelines' emergency planning and notification procedures; indeed, such procedures are precisely the sort of procedures a reasonably prudent operator of any gas pipeline facility would maintain in ordinary course given that their systems transport commercially valuable, pressurized (natural flammable, toxic, or corrosive) gasses. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their procedures (as well as manage any resulting compliance costs).

V. Regulatory Analyses and Notices

A. Authority for This Rule

This proposed rule is published under the authority of the Secretary of Transportation delegated to the PHMSA Administrator pursuant to 49 CFR 1.97. Among the statutory authorities delegated to PHMSA are those set forth in the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*). 49 U.S.C. 60102 grants authority to issue standards for the transportation of gas via any part 192-regulated gathering pipelines to protect public safety and the environment; and 49 U.S.C. 60102(b)(5) specifies that PHMSA must consider both public safety and environmental benefits.

This NPRM proposes to implement several provisions of the PIPES Act of 2020, including those codified at 49 U.S.C. 60102, 60105, 60106, and 60109. Section 60102 authorizes the Secretary of Transportation to issue regulations governing the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of gas pipeline facilities, including gas transmission, gas distribution, offshore gas gathering, and Types A, B, and C gas gathering pipelines, each of which would be subject to various proposed requirements in this NPRM. Sections 60105 and 60106 permit States to assume safety authority over intrastate pipelines, including gas and hazardous liquid pipelines, and underground natural gas storage facilities through certifications or agreements with PHMSA, while section 60107 authorizes the Secretary to establish requirements governing award of grants supporting

[182] The severity of harms to public safety and the environment from a rupture on a gas pipeline depend (inter alia) on the volume of gas released, the duration of the release, and the time before mitigation/response actions are initiated and completed.

[183] 87 FR at 20949–52, 20972, 20972.

[184] 87 FR 20952–53.

[185] PHMSA understands that in so doing, the § 192.635 definition of ''notification of potential rupture'' referenced within § 192.3 would apply to all part 192-regulated gas gathering pipelines as well.

State pipeline safety programs. Additionally, 49 U.S.C. 60117 authorizes the Secretary of Transportation to direct operators of those gas pipeline facilities to submit reports to PHMSA to inform PHMSA's regulatory oversight activities. As described above, 49 U.S.C. 60102, 60105, and 60109 also require the Secretary to issue regulations updating PHMSA regulations in 49 CFR parts 192 and 198.

B. Executive Orders 12866 and 14094; DOT Regulatory Policies and Procedures

Executive Order 12866 (''Regulatory Planning and Review''), as amended by Executive Order 14094 (''Modernizing Regulatory Review''), requires that agencies ''should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating.'' [186] Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, Executive Order 12866 requires that agencies maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach. Similarly, DOT Order 2100.6A (''Rulemaking and Guidance Procedures'') requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts.

Executive Order 12866 (as amended by Executive Order 14094) and DOT Order 2100.6A require that PHMSA submit ''significant regulatory actions'' to the Office of Management and Budget (OMB) for review. The proposed rule has been determined to be significant under section 3(f) of Executive Order 12866 (as amended by section 1(b) of Executive Order 14094) and DOT Order 2100.6A and was reviewed by the Office of Information and Regulatory Affairs (OIRA) within OMB.

Consistent with Executive Order 12866 (as amended by Executive Order 14094) and DOT Order 2100.6A, PHMSA has prepared a PRIA assessing the benefits and costs of the proposed rule as well as reasonable alternatives. PHMSA estimates the proposed rule will result in unquantified public safety and environmental benefits associated with preventing and mitigating incidents on gas distribution and other part 192-regulated gas pipeline facilities. PHMSA estimates annualized costs of $110 million per year (using a 3 percent discount rate) due to costs associated with the proposed requirements for updating emergency response plans, updating O&M manuals, keeping records, gas monitoring by qualified employees, and assessing and upgrading district regulator stations. For the full cost/benefit analysis, please see the PRIA in the rulemaking docket. PHMSA seeks comment on the PRIA, its approach, and the accuracy of its estimated costs and benefits.

C. Environmental Justice

Executive Order 12898 (''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations''),[187] directs Federal agencies to take appropriate and necessary steps to identify and address disproportionately high and adverse effects of Federal actions on the health or environment of minority and low-income populations to the greatest extent practicable and permitted by law. DOT Order 5610.2C (''U.S. Department of Transportation Actions to Address Environmental Justice in Minority Populations and Low-Income Populations'') establishes departmental procedures for effectuating Executive Order 12898 promoting the principles of environmental justice through full consideration of environmental justice principles throughout planning and decision-making processes in the development of programs, policies, and activities—including PHMSA rulemaking.

PHMSA has evaluated this NPRM under DOT Order 5610.2C and Executive Order 12898 and has preliminarily determined it will not cause disproportionately high and adverse human health and environmental effects on minority and low-income populations. The proposed rule is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor is it expected to result in any adverse environmental or health impact any particular population, region, or community. Rather, PHMSA anticipates the rulemaking will reduce the safety and environmental risks associated with losses of integrity on gas pipeline facilities—particularly gas distribution pipelines in urban or rural areas posing higher risks due to their vintage, material, and proximity to minority and low-income communities in the vicinity of those pipelines.[188] Lastly, as explained in the draft environmental assessment in the rulemaking docket, PHMSA anticipates that the regulatory amendments in this proposed rule will yield greenhouse gas emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority and low-income, populations, underserved and other disadvantaged communities. This finding is consistent with the most recent Environmental Justice Executive Order 14096—Revitalizing Our Nation's Commitment to Environmental Justice for All, by achieving several goals including continuing to deepen the Administration's whole of government approach to environmental justice and to better protect overburden communities from pollution and environmental harms.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act, as amended by the Small Business Regulatory Flexibility Fairness Act of 1996 (5 U.S.C. 601 *et seq.*), generally requires Federal agencies to prepare an initial regulatory flexibility analysis (IRFA) for a proposed rule subject to notice-and-comment rulemaking under the Administrative Procedure Act. 5 U.S.C. 603(a).[189] Executive Order 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'') [190] obliges agencies to establish procedures promoting compliance with the Regulatory Flexibility Act; DOT's implementing guidance is available on its website.[191]

This NPRM was developed in accordance with Executive Order 13272 and DOT guidance to ensure compliance with the Regulatory Flexibility Act and provide appropriate consideration of the potential impacts of the rulemaking on small entities. PHMSA conducted an IRFA, which has been made available in the docket for this rulemaking and is summarized below. A description of the reasons why

[186] E.O. 12866 is available at 58 FR 51735 (Oct. 4, 1993); E.O. 14094 is available at 88 FR 21879 (Apr. 6, 2023).

[187] 59 FR 7629 (Feb. 16, 1994).

[188] *See, e.g.,* Luna & Nicholas, ''An Environmental Justice Analysis of Distribution-Level Natural Gas Leaks in Massachusetts, USA,'' 162 Energy Policy 112778 (Mar. 2022); Weller et al., ''Environmental Injustices of Leaks from Urban Natural Gas Distribution Systems: Patterns Among and Within 13 U.S. Metro Areas,'' Environ. Sci & Tech. (May 11, 2022).

[189] Agencies are not required to conduct an IRFA if the head of the agency certifies that the proposed rule will not have a significant impact on a substantial number of small entities. 5 U.S.C. 605.

[190] 67 FR 53461 (Aug. 16, 2002).

[191] DOT, ''Rulemaking Requirements Concerning Small Entities'', *https://www.transportation.gov/regulations/rulemaking-requirements-concerning-small-entities* (last updated May 18. 2012).

PHMSA is considering this action and a succinct statement of the objectives of, and legal basis for, the proposed rule are described elsewhere in the preamble for this rule and not repeated here. PHMSA seeks comment on whether the proposed rule, if adopted, would have a significant economic impact on a significant number of small entities.

Description and Estimate of the Number of Small Entities to Which the Proposed Rule Would Apply

PHMSA analyzed privately owned entities (inclusive of investor-owned entities) that could be impacted by the rule, which include companies with natural gas extraction, pipeline transportation, and natural gas distribution businesses, as well as entities with another primary business. PHMSA determined whether these entities were small entities based on the size of the parent entity and using the relevant SBA size standards set out in Table 43 of the PRIA. PHMSA also analyzed publicly owned entities that could be impacted by the rule, including State, municipal, and other political subdivision entities. Publicly owned entities with population less than 50,000 are considered small.

PHMSA identified 1,239 gas distribution parent entities and determined that of these parent entities, 92 percent (1,135 parent entities) are classified as ''small'' based on the relevant criteria listed above. PHMSA also identified 831 gas transmission and gathering parent entities in this analysis that do not also operate distribution systems. Of these gas transmission and gas gathering parent entities, 82 percent are classified as ''small'' (681 parent entities). Because PHMSA did not have sufficient information to individually categorize master meter operators or operators of small LPGs by size, PHMSA conservatively made the over-inclusive decision to consider all master meter operators and operators of small LPGs to be small entities for purposes of its analysis.

Description of Projected Reporting, Recordkeeping, and Other Compliance Requirements of the Proposed Rule, Including an Estimate of the Classes of Small Entities Which Would Be Subject to the Requirement and the Type of Professional Skills Necessary for Preparation of the Report or Record

PHMSA analyzed the costs of compliance for the small gas distribution, gas transmission and gathering, and master meter and small LPG operators. PHMSA assessed the annualized cost for gas distribution operators based on the number of services, and provided a minimum, average, and maximum annualized cost estimate for each size category. For small gas distribution operators with 100,000 or fewer services, PHMSA calculated annualized estimated compliance costs that ranged from $8,051 to $10,528 depending on the cost scenario and discount rate.[192] For gas transmission and gathering operators, PHMSA calculated minimum, average, and maximum annualized estimated compliance costs that ranged from $44 to $52,029 depending on the cost scenario, industry type (transmission or gathering), and discount rate. For small master meter systems, PHMSA estimated pre-tax annualized compliance costs for individual operators from $4,421 to $4,590, depending on the discount rate. For small LPG systems, PHMSA estimated pre-tax annualized compliance costs for individual operators from $4,764 to $4,928, again depending on the discount rate.

PHMSA then calculated cost-to-revenue ratios using the calculated compliance costs of each small parent entity. PHMSA estimated that 98 percent of small gas distribution parent entities will face after-tax compliance costs of less than 1 percent of revenue under all evaluated cost scenarios. PHMSA estimated that 80 to 82 percent of small gas transmission parent entities operators will incur after-tax compliance costs of less than 1 percent of revenue. Under the maximum cost scenario, PHMSA estimates that 1 percent of small parent entities will incur compliance costs above 1 percent but below 3 percent of revenue. Under this maximum cost scenario, PHMSA also estimates that one small parent entity will incur compliance costs above 3 percent of revenue. However, PHMSA believes the maximum cost scenario is unlikely, as it assumes the entirety of estimated new and replaced lines are attributable to a single operator.[193] For master meter operators and operators of small LPGs, PHMSA calculated the break-even value of annual revenue that would be required for their calculated after-tax compliance costs to be 1 percent and 3 percent of revenue. For master meter operators, PHMSA estimated that revenue would need to be $442,122 or less for compliance costs to be 1 percent of revenue and that revenue would need to be $147,374 or less for compliance costs to be 3 percent of revenue. For operators of small LPGs, PHMSA estimated that revenue would need to be $476,357 or less for compliance costs to be 1 percent of revenue and that revenue would need to be $158,786 or less for compliance costs to be 3 percent of revenue.

[192] See PRIA Table 45.

[193] For the other 18% of operators, PHMSA did not have sufficient data to calculate the revenue percentage for the compliance costs of the rule at this time. PHMSA seeks comment on compliance costs generally, but in particular for transmission and gathering operators for which sufficient data was not available.

Relevant Federal Rules Which May Duplicate, Overlap or Conflict With the Proposed Rule

PHMSA did not identify any Federal rules that may duplicate, overlap, or conflict with the proposed rule. In Section 7.6 of the PRIA accompanying this NPRM, PHMSA provides details on other Federal regulations that may impact operators of gas pipelines.

Description and Analysis of Significant Alternatives to the Proposed Rule Considered

PHMSA analyzed a number of alternatives to the NPRM, which are described in detail in Section 2 of the PRIA accompanying this NPRM. In addition to retaining the status quo and not issuing the proposal, which PHMSA determined would fail to satisfy PIPES Act mandates to improve safety and update PHMSA regulations, PHMSA also analyzed:

1. Retaining DIMP requirements for small LPG operators and imposing the updated DIMP requirements of this NPRM on those same operators.
2. Extending to all part 192-regulated pipelines an exception that currently allows, for distribution mains only, distribution operator personnel involved in the same construction task to inspect each other's work.
3. An alternative compliance date.
4. Imposing an ICS requirement for emergency response.
5. Requiring all future construction projects associated with installations, modifications, replacements, or system upgrades on gas distribution pipelines to have licensed professional engineer approval and stamping.
6. Requiring gas distribution operators to develop and follow an MOC process as outlined in ASME/ANSI B31.8S.

PHMSA did not identify any viable alternative that could accomplish the stated objectives of applicable statutes while further minimizing any significant economic impact of the proposed rule on small entities. As discussed in more detail elsewhere in this preamble and in Section 2 of the PRIA for this NPRM, PHMSA determined that these requirements could result in reductions in safety benefits that were not justified by any potential cost savings (*e.g.,* the proposal to extend the exception for distribution mains that allows distribution operator personnel to inspect each other's work on the same construction task to all part-192 regulated pipelines) or impose costs on small entities that were not justified by any increased safety benefits. PHMSA therefore declined to propose these alternatives but seeks comment on them in this proposed rule.

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

PHMSA analyzed this proposed rule in accordance with the principles and criteria contained in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments'') [194] and DOT Order 5301.1A (''Department of Transportation Programs, Policies, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). Executive Order 13175 requires agencies to ensure meaningful and timely input from Tribal government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities, or the relationship or distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the proposed rule and does not expect it will significantly or uniquely affect Tribal communities or Indian Tribal governments. The proposed rule's regulatory amendments are facially neutral and will have broad, national scope. PHMSA, therefore, does not expect this rule to significantly or uniquely affect Tribal communities, impose substantial compliance costs on Native American Tribal governments, or mandate Tribal action. And insofar as PHMSA expects the NPRM will improve safety and reduce environmental risks associated with gas distribution pipelines, PHMSA expects it will not entail disproportionately high adverse risks for Tribal communities. Therefore, PHMSA concludes that the funding and consultation requirements of Executive Order 13175 and DOT Order 5301.1A do not apply to this proposed rule.

While PHMSA is not aware of specific Tribal-owned business entities that operate part 192-regulated gas pipelines, any such business entities could be subject to direct compliance costs as a result of this proposed rule. PHMSA seeks comment on the applicability of Executive Order 13175 to this proposed rule and the existence of any Tribal-owned business entities operating pipelines affected by the proposed rule (along with the extent of such potential impacts).

[194] 65 FR 67249 (Nov. 6, 2000).

F. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. If adopted, the proposals in this rulemaking would impose new notification and recordkeeping requirements for all part 192-regulated pipelines, including gas distribution, gas transmission and gathering pipelines.

PHMSA proposes to require gas distribution operators to review their integrity management plans to ensure that the plans identify specific threats such as: (1) certain materials, such as cast iron and other piping with known issues, (2) the age of each component of the operator's pipelines along with the overall age of its system, (3) overpressurization of low-pressure systems, and (4) extreme weather and geohazards. PHMSA also proposes that, when identifying and implementing measures to address those risks, operators must address (at a minimum) the risks associated with each of the following: the presence of known issues, the age of each part of a pipeline along with the overall age of the system, and (for operators of low-pressure gas distribution systems) overpressurization. PHMSA plans to revise the ''Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines'' information collection that is currently approved under OMB Control No. 2137–0625 to include this new requirement. Since pipeline operators are already required to review and update their integrity management plans on a regular basis, PHMSA expects operators to incur minimal burden in complying with this information collection request.

PHMSA also proposes to repeal the requirement for operators of small LPGs to participate in the distribution integrity management program. Based on a recent study, PHMSA estimates there are as many as 4,492 small LPG operators. PHMSA proposes to create a new form, PHMSA Form 7100.1–2, to collect limited data from these operators of small LPGs on an annual basis. As a result, PHMSA expects the burden of the ''Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines'' information collection under OMB Control No. 2137–0625 to be reduced and the burden for information collection under OMB Control No. 2137–0522 for the collection of annual and incident report data to increase due to the creation of the new form. Specifically, PHMSA expects each small LPG operator to spend 6 hours, annually, completing the new report form, resulting in an increase of 4,492 responses and 26,952 hours to the overall burden for the information collection under OMB Control No. 2137–0522. For the information collection under OMB Control No. 2137–0625, PHMSA previously estimated there were 2,539 operators of small LPG systems. Consequently, PHMSA expects the burden of that currently approved collection to be reduced by 2,539 responses and 66,014 hours due to the removal of small LPG operators. PHMSA also plans to revise the ''Gas Distribution Annual Report Form F7100.1–1'' information collection currently approved under OMB Control No. 2137–0629 to include the newly proposed requirements. For gas distribution pipelines, PHMSA proposes to collect additional information such as the number and miles of low-pressure service pipelines, including their overpressure protection methods.

PHMSA proposes codifying within the pipeline safety regulations its State Inspection Calculation Tool (SICT). The SICT is one of many factors used to help states determine the base level amount of time needed for administering adequate pipeline safety programs and is a consideration when PHMSA awards grants to states supporting those programs. PHMSA plans to revise the ''Gas Pipeline Safety Program Performance Progress Report'' and ''Hazardous Liquid Pipeline Safety Program Performance Progress Report'' information collection currently approved under OMB Control No. 2137–0584 to account for the burden incurred by state representatives to report data via the SICT.

Operators are required to maintain records pertaining to various aspects of their pipeline systems. Under the proposals in this rulemaking, PHMSA would expand the recordkeeping requirements for all gas pipeline operators. Operators would be required to revise their emergency response plans to include procedures ensuring prompt and effective response by adding emergencies involving a release of gas that results in a fatality, as well as any other emergency deemed significant by the operator. In the event of a release of gas resulting in one or more fatalities, all operators would also be required to immediately and directly notify emergency response officials upon receiving notice of the same. For distribution pipeline operators only, PHMSA's proposed expansion of the list of emergencies discussed above would also include the unintentional release of gas and shutdown of gas service to 50 or more customers (or 50 percent of its customers if it has fewer than 100 total customers). Operators would need to immediately and directly notify emergency response officials on receiving notice of the same.

PHMSA also proposes a series of regulatory amendments requiring gas distribution operators to update their emergency response plans to improve communications with the public during an emergency. First, PHMSA proposes to introduce a new requirement for gas distribution operators to establish and maintain communications with the general public as soon as practicable during an emergency. Second, PHMSA proposes to add a new requirement for gas distribution pipeline operators to develop and implement, no later than 18 months after the publication of any final rule in this proceeding, an opt-in system to keep their customers informed of the status of pipeline safety in their communities should an emergency occur. PHMSA also proposes a new requirement for gas distribution operators to notify their customers and public officials in certain instances. PHMSA plans to create a new information collection to cover these notification requirements for gas distribution operators. PHMSA will request a new Control Number from OMB for these information collections. PHMSA will submit these information collection requests to OMB for approval based on the proposed requirements in this rule.

Operators would also be required to review and update their O&M manuals as needed pursuant to the proposal. Gas distribution operators would also be required to document and maintain records on their MOC processes and additional safety procedures. Further, PHMSA proposes that all gas distribution pipeline operators identify and maintain traceable, verifiable, and complete maps and records documenting the characteristics of their systems that are critical to ensuring proper pressure controls for their gas distribution pipeline systems and to ensure that those records are accessible to anyone performing or supervising design, construction, and maintenance activities on their systems. PHMSA proposes to specify that these required records include (1) the maps, location, and schematics related to underground piping, regulators, valves, and control lines; (2) regulator set points, design capacity, and valve-failure mode (open/closed); (3) the system's overpressure-protection configuration; and (4) any other records deemed critical by the operator. PHMSA proposes to require that the operator maintain these integrity-critical records for the life of the pipeline because these records are critical to the safe operation and pressure control of a gas distribution system. PHMSA plans to revise the ‘‘Recordkeeping Requirements for Gas Pipeline Operators'' information collection currently approved under OMB Control No. 2137–0049 to include the newly proposed recordkeeping requirements. PHMSA expects the impact to be minimal and absorbed by the currently approved burden for this information collection.

The information collections in this proposed rule would be required through the proposed amendments to the pipeline safety regulations, 49 CFR 190–199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burden under the proposed rule is estimated as follows:

1. *Title:* Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines.

OMB Control Number: 2137–0625.

Current Expiration Date: 5/31/2024.

Abstract: The pipeline safety regulations require operators of gas distribution pipelines to develop and implement integrity management (IM) programs. The purpose of these programs is to enhance safety by identifying and reducing pipeline integrity risks. PHMSA requires operators to maintain records demonstrating compliance with this information collection for 10 years. PHMSA uses the information to evaluate the overall effectiveness of gas distribution Integrity Management requirements.

PHMSA proposes to repeal the requirement for operators of small LPGs to participate in the distribution IM program. PHMSA previously estimated that there were 2,539 operators of small LPG systems. Consequently, PHMSA expects the burden of this information collection to be reduced by 2,539 responses and 66,014 hours due to the removal of small LPG operators.

Affected Public: Owners and operators of gas distribution pipelines.

Annual Reporting Burden:

Total Annual Responses: 1,343.

Total Annual Burden Hours: 657,178.

Frequency of Collection: On occasion.

2. *Title:* Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 3/31/2025.

Abstract: This mandatory information collection request would require owners and/or operators of gas pipeline systems to make and maintain records in accordance with the requirements prescribed in 49 CFR part 192 and to provide information to the Secretary of Transportation at the Secretary's request. Certain records are maintained for a specific length of time while others are required to be maintained for the life of the pipeline. PHMSA uses these records to verify compliance with regulated safety standards and to inform the agency on possible safety risks.

Affected Public: Operators of gas pipeline systems.

Annual Reporting Burden:

Total Annual Responses: 4,056,052.

Total Annual Burden Hours: 5,031,086.

Frequency of Collection: On occasion.

3. *Title:* Emergency Notification Requirements for Gas Operators.

OMB Control Number: Will Request from OMB.

Current Expiration Date: TBD.

Abstract: This information collection covers the requirement for owners and operators of gas distribution pipelines to notify their customers and public officials in the event of certain instances pertaining to pipeline safety. PHMSA estimates there will be an average of 75 incidents per year where gas distribution operators will need to make such notifications. PHMSA expects gas distribution operators will spend approximately 8 hours notifying the public in each instance, resulting in an annual burden of 600 hours. PHMSA expects gas distribution operators to spend an additional 2 hours per incident notifying their customers, resulting in an added burden of 150 hours. PHMSA also requires operators of all gas pipelines to notify and communicate with emergency responders if gas is detected inside or near a building; fire is located near or directly involving a pipeline facility; and explosion occurs near or directly involving a pipeline facility; or in the event of a natural disaster. Based on incident report trends, PHMSA expects there to be 44 incidents (1 gas gathering, 16 gas transmission, 27 gas distribution) annually, which would require gas operators to notify emergency responders. PHMSA estimates each notification will take 2 hours per incident resulting in an annual burden of 88 hours.

Affected Public: Owners and operators of gas pipelines.

Annual Reporting Burden:

Total Annual Responses: 194.

Total Annual Burden Hours: 838.

Frequency of Collection: On occasion.

4. *Title:* Annual and Incident Report for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 03/31/2026.

Abstract: This mandatory information collection covers the collection of data from operators of natural gas pipelines, underground natural gas storage facilities, and liquefied natural gas (LNG) facilities for annual reports. 49 CFR 191.17 requires operators of underground natural gas storage facilities, gas transmission systems, and gas gathering systems to submit an annual report by March 15 for the preceding calendar year. The Gas Distribution NPRM proposes to collect limited data from operators of small LPGs. PHMSA proposes to create Form F7100.1–2. to collect this data, ''Small LPG Annual Report Form F7100.1–2.'' The burden for this information collection is being revised to account for this new data collection. PHMSA estimates that 4,492 small LPG operators will spend 6 hours annually completing this new report resulting in an increase of 4,492 responses and 26,952 hours to the currently approved burden for this information collection.

Affected Public: Owners and operators of gas distribution pipelines.

Annual Reporting Burden:

Total Annual Responses: 7,813.

Total Annual Burden Hours: 122,763.

Frequency of Collection: Annually.

5. *Title:* Gas Pipeline Safety Program Performance Progress Report and Hazardous Liquid Pipeline Safety Program Performance Progress Report.

OMB Control Number: 2137–0584.

Current Expiration Date: 5/31/2025.

Abstract: 49 U.S.C. 60105 sets forth specific requirements a State must meet to qualify for certification status to assume regulatory and enforcement responsibility for intrastate pipelines, *i.e.,* state adoption of minimum Federal safety standards, state inspection of pipeline operators to determine compliance with the standards, and state provision for enforcement sanctions substantially the same as those authorized by Chapter 601, Title 49 of the U.S. Code. A State must submit an annual certification to assume responsibility for regulating intrastate pipelines, and states who receive Federal grant funding must have adequate damage prevention plans and associated records in place. PHMSA uses this information to evaluate a State's eligibility for Federal grants and to enforce regulatory compliance. This information collection request requires a participating State to annually submit a Gas Pipeline Safety Program Performance Progress Report and Hazardous Liquid Pipeline Safety Program Performance Progress Report to PHMSA's Office of Pipeline Safety (OPS) signifying compliance with the terms of the certification and to maintain records detailing a damage prevention plan for PHMSA inspectors whenever requested. The purpose of the collection is to exercise oversight of the grant program and to ensure that States are compliant with Federal pipeline safety regulations. PHMSA is revising this information collection to include the reporting of inspection data via the State Inspection Calculation Tool (SICT). PHMSA expects 66 State representatives to submit data pertaining to the number of safety inspectors employed in their pipeline safety programs via the SICT. PHMSA estimates that, on average, State representatives will spend 8 hours annually compiling and submitting SICT data.

Affected Public: Pipeline operators applying for State grants.

Annual Reporting Burden:

Total Annual Responses: 183.

Total Annual Burden Hours: 5,001.

Frequency of Collection: Annual.

6. *Title:* Annual for Gas Distribution Operators.

OMB Control Number: 2137–0629.

Current Expiration Date: 06/30/2026.

Abstract: This mandatory information collection request would require operators of gas distribution pipeline systems to submit annual report data to the Office of Pipeline Safety in accordance with the regulations stipulated in 49 CFR part 191 by way of form PHMSA F 7100.1–1. The form is to be submitted once for each calendar year. The annual report form collects data about the pipe material, size, and age. The form also collects data on leaks from these systems as well as excavation damages. PHMSA uses the information to track the extent of gas distribution systems and normalize incident and leak rates.

The Gas Distribution NPRM proposes to revise the Annual Report for Gas Distribution Operators, form PHMSA F 7100.1–1, to collect additional information on gas distribution systems such as the number and miles of low-pressure service pipelines, including their overpressure protection methods.

The current approved burden for gas distribution operators to complete this report is 20 hours, annually. As a result of the proposed change, the burden for completing PHMSA F 7100.1-collection is being increased by 6 hours annually, resulting in an overall burden of 26 hours, per annual report, for gas distribution operators.

Affected Public: Owners and operators of gas distribution pipelines.

Annual Reporting Burden:

Total Annual Responses: 1,446.

Total Annual Burden Hours: 37,596.

Frequency of Collection: Annually.

Requests for a copy of these information collections should be directed to Angela Hill via email at *angela.hill@dot.gov* or via telephone (202) 366–4595.

Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected;

(d) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques; and

(e) Ways the collection of this information is beneficial or not beneficial to public safety.

Send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW, Washington, DC 20503.

G. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (UMRA, 2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate of $100 million or more (in 1996 dollars) in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate.

As explained further in the PRIA, PHMSA does not expect that the proposed rule will impose enforceable duties on State, local, or Tribal governments or on the private sector of $100 million or more (in 1996 dollars) in any one year. A copy of the PRIA is available for review in the docket. Therefore, the requirement to prepare a statement pursuant to UMRA does not apply.

H. National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA, 42 U.S.C. 4321 *et seq.*) requires Federal agencies to prepare a detailed statement on major Federal actions significantly affecting the quality of the human environment. The Council on Environmental Quality's implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (''Procedures for Considering Environmental Impacts'') establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

PHMSA has completed a draft environmental assessment and expects that an environmental impact statement will not be required for this rulemaking because it will not have a significant impact on the human environment. To the extent that the proposed rule could impact the environment, PHMSA expects those impacts will be primarily beneficial impacts from reducing the likelihood and consequences of incidents on gas distribution pipelines and other part 192-regulated gas pipelines. A copy of the draft environmental assessment is available in the docket. PHMSA invites comment on the potential environmental impacts of this proposed rule.

I. Executive Order 13132: Federalism

PHMSA has analyzed this proposed rule in accordance with the principles and criteria contained in Executive Order 13132 (''Federalism'') [195] and the Presidential Memorandum titled ''Preemption.'' [196] Executive Order 13132 requires agencies to ensure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.''

PHMSA does not expect this proposed rule will have a substantial direct effect on State and local governments, the relationship between the Federal Government and the States, or the distribution of power and responsibilities among the various levels of government. The provisions proposed involving SICT codify in regulation existing practice and do not impose any noteworthy additional direct compliance costs on State and local governments.

States are generally prohibited by 49 U.S.C. 60104(c) from regulating the safety of interstate pipelines. States that have submitted a current certification under 49 U.S.C. 60105(a) can augment Federal pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate.

In this instance, the preemptive effect of the proposed rule would be limited to the minimum level necessary to achieve the objectives of the statutory authority under which the proposed rule is promulgated. While the 49 CFR part 192 safety requirements in this proposed rule may, if adopted in a final rule, preempt some State requirements, preemption arises by operation of 49 U.S.C. 60104, and this proposed rule would not impose any regulation that has substantial direct effects on the states, the relationship between the national government and the states, or the distribution of power and responsibilities among the various levels of government. Therefore, the PHMSA has determined that the consultation and funding requirements of Executive Order 13132 do not apply to this proposed rule.

J. Executive Order 13211: Significant Energy Actions

Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'') [197] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' Executive Order 13211 defines a ''significant energy action'' as any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation that (1)(i) is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) is designated by OIRA as a significant energy action.

This proposed rule is not anticipated to be a ''significant energy action'' under Executive Order 13211. It is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, the OIRA has not designated this proposed rule as a significant energy action.

K. Privacy Act Statement

In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to better inform its rulemaking process. DOT posts these comments without edit, including any personal information the commenter provides, to *https://www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *https://www.dot.gov/privacy.*

L. Regulation Identifier Number

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Regulatory and Deregulatory Actions (Unified Agenda). The RIN contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

M. Executive Order 13609 and International Trade Analysis

Executive Order 13609 (''Promoting International Regulatory Cooperation'') [198] requires agencies to consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards so long as the standards have a legitimate domestic objective, such as providing for safety,

[195] 64 FR 43255 (Aug. 10, 1999).

[196] 74 FR 24693 (May 22, 2009).

[197] 66 FR 28355 (May 22, 2001).

[198] 77 FR 26413 (May 4, 2012).

and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they serve as the basis for U.S. standards. PHMSA participates in the establishment of international standards to protect the safety of the American public.

PHMSA assessed the effects of the proposed rule and expects that it will not cause unnecessary obstacles to foreign trade.

N. Cybersecurity and Executive Order 14028

Executive Order 14028 (''Improving the Nation's Cybersecurity'') [199] directed the Federal government to improve its efforts to identify, deter, and respond to ''persistent and increasingly sophisticated malicious cyber campaigns.'' Accordingly, PHMSA has assessed the effects of this NPRM to determine what impact the proposed regulatory amendments may have on cybersecurity risks for pipeline facilities and has preliminarily determined that this NPRM will not materially affect the cybersecurity risk profile for pipeline facilities.

Operator DIMPs, O&M manuals and procedures, and facility design standards are largely static materials; because those materials are not means of manipulating pipeline operations in real-time, PHMSA's proposed amendments of requirements governing those materials are therefore unlikely to increase the risk of cybersecurity incidents. Although other proposals within the NPRM—in particular, real-time overpressurization monitoring and customer opt-in/opt-out emergency communication systems—may offer more attractive targets for cybersecurity incidents, PHMSA understands the incremental additional risk from the NPRM's proposed regulatory amendments to be minimal. Operator compliance strategies for these proposed requirements will be subject to current Transportation Security Agency (TSA) pipeline cybersecurity directives; [200] PHMSA further understands Cybersecurity & Infrastructure Security Agency (CISA) and the Pipeline Cybersecurity Initiative (PCI) of the U.S. Department of Homeland Security conduct ongoing activities to address cybersecurity risks to U.S. pipeline infrastructure and may introduce other cybersecurity requirements and guidance for gas pipeline operators.[201] Lastly, because PHMSA expects that this NPRM's proposed regulatory amendments (notably those regarding emergency response planning) will reduce the severity of any gas pipeline incidents that occur, this rulemaking could reduce the public safety and the environmental consequences in the event of a cybersecurity incident on a gas pipeline.

[199] 86 FR 26633 (May 17, 2021).

[200] *E.g.,* TSA, ''Ratification of Security Directive,'' 86 FR 38209 (July 20, 2021) (ratifying TSA Security Directive Pipeline–2012–01, which requires certain pipeline owners and operators to conduct actions to enhance pipeline cybersecurity).

[201] *See, e.g.,* CISA, National Cyber Awareness System Alerts, *https://www.cisa.gov/uscert/ncas/alerts* (last accessed Feb. 1, 2023).

M. Severability

The purpose of this proposed rule is to operate holistically in addressing a panoply of issues necessary to ensure safe operation of regulate pipelines, with a focus on gas distribution pipelines' protection against overpressurization events. However, PHMSA recognizes that certain provisions focus on unique topics. Therefore, PHMSA preliminarily finds that the various provisions of this proposed rule are severable and able to function independently if severed from each other. In the event a court were to invalidate one or more of the unique provisions of any final rule issued in this proceeding, the remaining provisions should stand, thus allowing their continued effect.

List of Subjects

49 CFR Part 191

Liquefied petroleum gas, Pipeline reporting requirements.

49 CFR Part 192

District regulator stations, Emergency response, Gas monitoring, Integrity management, Inspections, Gas, Overpressure protection, Pipeline safety, Reporting and recordkeeping requirements.

49 CFR Part 198

State inspector staffing requirements.

For the reasons provided in the preamble, PHMSA proposes to amend 49 CFR parts 191, 192, and 198 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for 49 CFR part 191 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3); 49 U.S.C. 5121, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. Revise § 191.11 to read as follows:

§ 191.11 Distribution system: Annual report.

(a) *General.* Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system, excluding a liquefied petroleum gas system that serves fewer than 100 customers from a single source, must submit an annual report for that system on DOT Form PHMSA F 7100.1–1. Each operator of a liquefied petroleum gas system that serves fewer than 100 customers from a single source must submit an annual report for that system on DOT Form PHMSA F 7100.1–2. Reports must be submitted each year, not later than March 15, for the preceding calendar year.

(b) *Not required.* The annual report requirement in this section does not apply to a master meter system, a petroleum gas system excepted from part 192 in accordance with § 192.1(b)(5), or an individual service line directly connected to a production pipeline or a gathering line other than a regulated gathering line as determined in § 192.8.

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

■ 3. The authority citation for 49 CFR part 192 continues to read as follows:

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

§ 192.3 [Amended]

■ 4. Amend § 192.3, by removing the last sentence ''This definition does not apply to any gathering line.'' from the definitions of ''Entirely replaced onshore transmission pipeline segments'', ''Notification of potential rupture'' and ''Rupture-mitigation valve (RMV)''.

§ 192.9 [Amended]

■ 5. Amend § 192.9 by:

■ a. Removing from paragraph (b) the last sentence;

■ b. Removing from paragraph (c) the last sentence; and

■ c. Removing from paragraph (e)(1)(iv) the words ''effective as of October 4, 2022.''

■ 6. Amend § 192.18 by revising paragraph (c) to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if an operator submits, pursuant to §§ 192.8, 192.9, 192.13, 192.179, 192.319, 192.506, 192.607, 192.619, 192.624, 192.632, 192.634, 192.636, 192.710, 192.712, 192.714, 192.745, 192.917, 192.921, 192.927, 192.933, 192.937, or

192.1007, a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*e.g.,* ''other technology'' or ''alternative equivalent technology'') than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety, or his or her delegate, informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.

■ 7. Amend § 192.195 by adding paragraph (c) to read as follows:

§ 192.195 Protection against accidental overpressuring.

* * * * *

(c) *Additional requirements for low-pressure distribution systems.* Each regulator station, serving a low-pressure distribution system, that is new, replaced, relocated, or otherwise changed after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE] must include:

(1) At least two methods of overpressure protection (such as a relief valve, monitoring regulator, or automatic shutoff valve) appropriate for the configuration and siting of the station;

(2) Measures to minimize the risk of overpressurization of the low-pressure distribution system that could be caused by any single event (such as excavation damage, natural forces, equipment failure, or incorrect operations), that either immediately or over time affects the safe operation of more than one overpressure protection device; and

(3) Remote monitoring of gas pressure at or near the location of overpressure protection devices.

■ 8. Amend § 192.305 by:

■ a. Lifting the stay of the section; and

■ b. Revising the section.

The revision reads as follows:

§ 192.305 Inspections: General.

(a) Each transmission pipeline and main that is new, replaced, relocated, or otherwise changed after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE] must be inspected to ensure that it is constructed in accordance with this subpart. Except as provided in paragraph (b) of this section, an operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

(b) For the construction inspection of a main that is new, replaced, relocated, or otherwise changed after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], operator personnel involved in the same construction task may inspect each other's work in situations where the operator could otherwise only comply with the construction inspection requirement in paragraph (a) of this section by using a third-party inspector. This justification must be documented and retained for the life of the pipeline.

■ 9. Amend § 192.517 by revising paragraph (b) to read as follows:

§ 192.517 Records.

* * * * *

(b) Each operator must maintain a record of each test required by §§ 192.509, 192.511, and 192.513 for the life of the pipeline.

(1) For tests performed before [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE] for which records are maintained, the record must continue to be maintained for the life of the pipeline.

(2) For tests performed on or after [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], the records must contain at least the following information:

(i) The operator's name, the name of the employee responsible for making the test, and the name of the company or contractor used to perform the test.

(ii) Pipeline segment pressure tested.

(iii) Test date.

(iv) Test medium used.

(v) Test pressure.

(vi) Test duration.

(vii) Leaks and failures noted and their disposition.

■ 10. Amend § 192.605 by adding paragraphs (b)(13), (f), and (g) to read as follows:

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

* * * * *

(b) * * *

(13) Implementing the applicable requirements for distribution systems in paragraphs (f) and (g) of this section, § 192.638, and § 192.640.

* * * * *

(f) *Overpressurization.* For distribution lines, the manual required by paragraph (a) of this section must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], include procedures for responding to, investigating, and correcting, as soon as practicable, the cause of overpressurization indications. The procedures must include the specific actions and an order of operations for immediately reducing pressure in or shutting down portions of the distribution system affected by an overpressurization.

(g) *Management of Change (MOC) Process.* For distribution lines, the manual required by paragraph (a) of this section must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], include a detailed MOC process for the following:

(1) Technology, equipment, procedural, and organizational changes, including:

(i) Installations, modifications, replacements, or upgrades to regulators, pressure monitoring locations, or overpressure protection devices;

(ii) Modifications to alarm set points or upper/lower trigger limits on monitoring equipment;

(iii) The introduction of new technologies for overpressure protection into the system;

(iv) Revisions, changes, or the introduction of new standard operating procedures for design, construction, installation, maintenance, and emergency response;

(v) Other changes that may impact the integrity or safety of the gas distribution system.

(2) Ensuring that personnel—such as an engineer with a professional engineer license, a subject matter expert, or another person who possesses the necessary knowledge, experience, and skills regarding gas distribution systems—review and certify construction plans associated with installations, modifications, replacements, or system upgrades for accuracy and completeness before the work begins. These personnel must be qualified to perform these tasks under subpart N of this part.

(3) Ensuring that any hazards introduced by a change are identified, analyzed, and controlled before resuming operations.

■ 11. Amend § 192.615 by:

■ a. Adding paragraphs (a)(3)(v) through (viii);

■ b. Revising paragraph (a)(8); and

■ c. Adding paragraphs (a)(13) and paragraph (d).

The additions and revision read as follows:

§ 192.615 Emergency plans.

(a) * * *

(3) * * *

(v) Notification of potential rupture (see § 192.635).

(vi) Beginning no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], release of gas that results in one or more fatalities.

(vii) Beginning no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], for distribution line operators only, unintentional release of gas and shutdown of gas service to 50 or more customers or, if the operator has fewer than 100 customers, 50 percent or more of its total customers.

(viii) Beginning no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], any other emergency deemed significant by the operator.

* * * * *

(8) Notifying the appropriate public safety answering point (*i.e.,* 9–1–1 emergency call center) where direct access to a 9–1–1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving notice of a gas pipeline emergency under paragraph (a)(3) of this section. The operator must coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of §§ 192.179, 192.634, or 192.636.

* * * * *

(13) For distribution line operators, beginning no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], establishing and maintaining communication with the general public in the operator's service area as soon as practicable during a gas pipeline emergency on a distribution line. The communication(s) must be in English, and any other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's service area; be in one or more formats or media accessible to the population in the operator's service area; continue through service restoration and recovery efforts; and provide the following:

(i) Information regarding the gas pipeline emergency;

(ii) The status of the emergency (*e.g.,* have the condition causing the emergency or the resulting public safety risks been resolved);

(iii) Status of pipeline operations affected by the gas pipeline emergency, and when possible, a timeline for expected service restoration; and

(iv) Directions for the public to receive assistance.

The operator must provide updates when the information in § 192.615(a)(13)(i) through (iv) changes.

* * * * *

(d) No later than [DATE 18 MONTHS AFTER THE PUBLICATION DATE OF THE RULE], each distribution line operator must develop and implement a system, including written procedures, that allows operators to rapidly communicate with customers in the event of a gas pipeline emergency under this section. The notification system must be voluntary for the public, allowing customers to opt-in (or opt-out) to receiving notifications from the system. The written procedures must provide for the following:

(i) A description of the notification system and how it will be used to notify customers of a gas pipeline emergency;

(ii) Who is responsible for the development, operation, and maintenance of the system;

(iii) How information on the system is delivered to customers, ensuring that all customers are notified of the existence of the system and necessary steps if they wish to opt-in (or opt-out);

(iv) Description of the system-wide testing protocol, including the testing interval (which must not be less than once per calendar year), to ensure the system is functioning properly and performing notifications as designed;

(v) Maintenance of the results of testing and operations history for at least 5 years;

(vi) Details regarding how the operator ensures messages are accessible in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area;

(vii) Message content, including updates as emergency conditions change;

(viii) A process to initiate, conduct, and complete notifications; and

(ix) Cybersecurity measures to protect the system and customer information.

■ 12. Add § 192.638 to read as follows:

§ 192.638 Distribution lines: Records for pressure controls.

(a) An operator of a distribution system, except those identified in paragraph (f) of this section, must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], identify and maintain traceable, verifiable, and complete records that document the characteristics of its pipeline system that are critical to ensuring proper pressure control. These records must include:

(1) Current location information (including maps and schematics) for regulators, valves, and underground piping (including control lines);

(2) Attributes of the regulator(s), such as set points, design capacity, and the valve failure position (open/closed);

(3) The overpressure protection configuration; and

(4) Other records deemed critical.

(b) If an operator does not have traceable, verifiable, and complete records as required by paragraph (a) of this section, the operator must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], identify and document those records needed and develop and implement procedures for collecting those records.

(c) The records identified in paragraph (a) of this section must be collected, generated, or updated on an opportunistic basis, as specified in § 192.1007(a)(3).

(d) An operator must ensure the records required by this section are accessible to all personnel responsible for performing or supervising design, construction, operations, and maintenance activities.

(e) An operator must retain the records required in this section for the life of the pipeline.

(f) Exception. This section does not apply to master meter systems, liquefied petroleum gas (LPG) distribution pipeline systems that serve fewer than 100 customers from a single source, or any individual service line directly connected to a transmission, gathering, or production pipeline that is not operated as part of a distribution system.

■ 13. Add § 192.640 to read as follows:

§ 192.640 Distribution lines: Presence of qualified personnel.

(a) An operator of a distribution system must conduct a documented evaluation of each construction project that begins after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE] to identify any potential project activities during which an overpressurization could occur at a district regulator station. This evaluation must occur before such activities begin. Activities that may present a potential for overpressurization include, but are not limited to, tie-ins, abandonment of distribution lines, and equipment replacement.

(b) If the evaluation in paragraph (a) of this section results in a determination that a potential for overpressurization exists during construction project activity, the operator must:

(1) Ensure that at least one person qualified according to subpart N of this part is present at that district regulator station, or at an alternative site, during the construction project activity that could cause an overpressurization;

(2) Monitor gas pressure with equipment capable of ensuring proper pressure controls; and

(3) Have the capability to promptly shut off the flow of gas or control overpressurization at a district regulator station.

(c) When monitoring the system as described in this section, the qualified personnel must be provided, at a minimum: information regarding the location of all valves necessary for isolating the pipeline system; pressure control records (see § 192.638); the authority to stop work (unless prohibited by operator procedures); operations procedures under § 192.605; and emergency response procedures under § 192.615.

(d) Exception. Distribution systems with a remote monitoring system in effect with the capability for remote or automatic shutoff need not comply with the requirements in paragraphs (a) through (c) of this section.

■ 14. Amend § 192.725 by revising paragraph (a) to read as follows:

§ 192.725 Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this section, each disconnected service line being restored to service on or after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE] must be tested in the same manner as a new service line (*i.e.,* tested in accordance with subpart J of this part) before being restored to service.

* * * * *

■ 15. Amend § 192.741 by:

■ a. Revising the title of the section, and

■ b. Adding paragraph (d).

The revision and addition read as follows:

§ 192.741 Pressure limiting and regulating stations: Telemetering, recording gauges, and other monitoring devices.

* * * * *

(d) On low-pressure distribution systems that are new, replaced, relocated, or otherwise changed after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], the operator must monitor the gas pressure in accordance with § 192.195(c)(3).

§ 192.1001 [AMENDED]

■ 16. Amend § 192.1001 by removing the definition of ''Small LPG Operator.''

■ 17. Amend § 192.1003 by adding paragraph (b)(4) to read as follows:

§ 192.1003 What do the regulations in this subpart cover?

* * * * *

(b) * * *

(4) A system of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

■ 18. Amend § 192.1005 by revising the title of the section to read as follows:

§ 192.1005 What must a gas distribution operator do to implement this subpart?

■ 19. Amend § 192.1007 by revising paragraphs (a)(3), (b), (c), and (d) to read as follows:

§ 192.1007 What are the required elements of an integrity management plan?

* * * * *

(a) * * *

(3) Identify additional information needed and provide a plan for obtaining that information over time (including the records specified in § 192.638(c)) through normal activities conducted on the pipeline (for example, design, construction, operations, or maintenance activities).

* * * * *

(b) *Identify threats.* The operator must consider the following categories of threats to each gas distribution pipeline: corrosion (including atmospheric corrosion); natural forces (including extreme weather, land movement, and other geological hazards); excavation damage; other outside force damage; material (including the presence and age of pipes such as cast iron, bare steel, unprotected steel, wrought iron, and historic plastics with known issues) or welds; equipment failure; incorrect operations; overpressurization of low-pressure distribution systems; and other threats that pose a risk to the integrity of a pipeline. An operator must also consider the age of the system, pipe, and components in identifying threats. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) *Evaluate and rank risk.*

(1) *General.* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (*e.g.,* contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances, areas with common materials, age, or environmental factors), and for which similar actions likely would be effective in reducing risk.

(2) *Certain pipe with known issues.* An operator must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], evaluate the risks in the distribution system resulting from pipelines with known issues based on the material (including, cast iron, bare steel, unprotected steel, wrought iron, and historic plastics with known issues), design, age, or past operating and maintenance history.

(3) *Low-pressure Distribution Systems.* An operator must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], evaluate the risks that could lead to or result from the operation of a low-pressure distribution system at a pressure that makes the operation of any connected and properly adjusted low-pressure gas burning equipment unsafe. In the evaluation of risks, an operator must:

(i) Evaluate factors other than past observed abnormal operating conditions (as defined in § 192.803) in ranking risks, including any known industry threats, risks, or hazards to public safety that could occur on its system based on knowledge gained from available sources;

(ii) Evaluate potential consequences associated with low-probability events unless a determination, supported and documented by an engineering analysis, or an equivalent analysis incorporating operational knowledge, demonstrates that the event results in no potential consequences and therefore no potential risk. An operator must notify PHMSA and State or local pipeline safety authorities, as applicable, in accordance with § 192.18 within 30 days of making such a determination. The notification must include the following:

(A) Date the determination was made;

(B) Description of the low-probability event being considered;

(C) Logic supporting the determination, including information from an engineering analysis, or an equivalent analysis incorporating operational knowledge;

(D) Description of any preventive and mitigative measures, including any measures considered but not taken;

(E) Details of the low-pressure system applicable to the event that results in no potential consequence and risk, including, at a minimum, the miles of pipe, number of customers, number of district regulators supplying the system, and other relevant information; and

(F) Written statement summarizing the documentation provided in the notification.

(iii) Evaluation of the configuration of primary and any secondary overpressure protection installed at district regulator stations (such as a relief valves, monitoring regulators, or automatic shutoff valves), the availability of gas pressure monitoring at or near overpressure protection equipment, and the likelihood of any single event (such as excavation damage, natural forces, equipment failure, or incorrect operations), that either immediately or over time, could result in an overpressurization of the low-pressure distribution system.

(d) *Identify and implement measures to address risks.*

(1) *General.* An operator must identify and implement measures to reduce the risks of failure of its distribution pipeline system. The measures identified and implemented must address, at a minimum, risks associated with the age of pipeline components, the overall age of the system and components, the presence of pipes with known issues, and overpressurization of low-pressure distribution systems. The measures must also include an effective leak management program (unless all leaks are repaired when found).

(2) *Minimization of Overpressurization of Low-Pressure Distribution Systems.* An operator must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], implement the following preventive and mitigative measures to minimize the risk of overpressurization of a low-pressure distribution system that could be the result of any single event or failure:

(i) Identify, maintain, and obtain, if necessary, pressure control records in accordance with §§ 192.638 and 192.1007(a)(3).

(ii) Confirm and document that each district regulator station meets the requirements of § 192.195(c)(1) through (3). If an operator determines that a district regulator station does not meet the requirements of § 192.195(c)(1) through (3), then by [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], the operator must take either of the following actions:

(A) Upgrade the district regulator station to meet the requirements of § 192.195(c)(1) through (3), or

(B) Identify alternative preventive and mitigative measures based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of implementing any alternative measures. The notification must be made in accordance with § 192.18(c) and must include a description of proposed alternative measures, identification and location of facilities to which the measures would be applied, and a description of how the measures would ensure the safety of the public, affected facilities, and environment.

* * * * *

§ 192.1015 [Removed]

■ 20. Remove § 192.1015.

PART 198—REGULATIONS FOR GRANTS TO AID STATE PIPELINE SAFETY PROGRAMS

■ 21. The authority citation for part 198 continues to read as follows:

Authority: 49 U.S.C. 60101 *et seq.;* 49 CFR 1.97.

■ 22. Amend § 198.3 by adding the definitions for ''Inspection person-day'' and ''State Inspection Calculation Tool (SICT)'' in alphabetical order to read as follows:

§ 198.3 Definitions.

* * * * *

Inspection person-day means all or part of a day, including travel, spent by State agency personnel in on-site or virtual evaluation of a pipeline system to determine compliance with Federal or State pipeline safety regulations.

* * * * *

State Inspection Calculation Tool (SICT) means a tool used to determine the required number of annual inspection person-days for a State agency.

* * * * *

■ 23. Amend § 198.13 by revising paragraph (c)(6) to read as follows:

§ 198.13 Grant-allocation formula.

* * * * *

(c) * * *

(6) Number of state inspection person-days, as determined by the SICT and other factors;

* * * * *

Issued in Washington, DC, on August 23, 2023, under authority delegated in 49 CFR 1.97.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

[FR Doc. 2023–18585 Filed 9–6–23; 8:45 am]

BILLING CODE 4910–60–P