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.

[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.

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

[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.