DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA–2018–0046; Amdt Nos. 191–29; 192–128]

RIN 2137–AF36

Pipeline Safety: Gas Pipeline Regulatory Reform

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

ACTION: Final rule; withdrawal of enforcement discretion.

SUMMARY: PHMSA is amending the Federal Pipeline Safety Regulations to ease regulatory burdens on the construction, maintenance, and operation of gas transmission, distribution, and gathering pipeline systems without adversely affecting safety. The amendments in this rule are based on rulemaking petitions from stakeholders, and DOT and PHMSA initiatives to identify appropriate areas where regulations might be repealed, replaced, or modified, and PHMSA's review of public comments. PHMSA also, as of the effective date of this final rule, withdraws the March 29, 2019 ''Exercise of Enforcement Discretion Regarding Farm Taps'' and the unpublished October 27, 2015 letter to the Interstate Natural Gas Association of America announcing a stay of enforcement pertaining to certain pressure vessels.

DATES: *Effective Date:* This rule is effective March 12, 2021.

Incorporation by reference date: The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of March 12, 2021.

Voluntary compliance date: March 12, 2021.

Delayed compliance date: Compliance with the amendments adopted in the rule is required beginning October 1, 2021.

Enforcement discretion withdrawal date: The withdrawal of 84 FR 11253 (Mar. 26, 2019) is effective as of March 12, 2021.

FOR FURTHER INFORMATION CONTACT: Sayler Palabrica, Transportation Specialist, by telephone at 202–366–0559.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of This Deregulatory Action

PHMSA is amending the Federal Pipeline Safety Regulations (PSR) at 49 CFR parts 191 and 192 to ease regulatory burdens on the construction, operation, and maintenance of gas transmission, distribution, and gathering pipeline systems without adversely affecting safety. These amendments include regulatory relief actions identified by internal agency review, petitions for rulemaking, and public comments submitted in response to a Department of Transportation (DOT) regulatory reform notice entitled ''Notification of Regulatory Review.'' [1]

On June 9, 2020, PHMSA published a notice of proposed rulemaking (NPRM) to seek public comments on proposed changes to the PSR.[2] A summary of those proposed changes, and PHMSA's response to stakeholder feedback on the individual provisions, is provided below in section III (*Analysis of Comments, GPAC Recommendations, and PHMSA's Response*).

B. Summary of PSR Amendments

The final rule makes the following amendments to 49 CFR parts 191 and 192:

A. Revision of certain requirements (at §§ 191.11, 192.740, and 192.1003) pertaining to farm taps giving operators the choice of managing inspections of pressure regulators serving farm taps under either their distribution integrity management plan (DIMP) or by following the inspection requirements at § 192.740;

B. Revision of certain requirements (at §§ 192.1003, 192.1005 and 192.1015) pertaining to master meter systems to exempt operators of these simple pipeline facilities from DIMP requirements that had been designed with complex distribution systems in mind;

C. Revision of certain reporting requirements (at §§ 191.12 and 192.1009) to eliminate a dedicated report form for mechanical fitting failures (MFFs), and modify other required report forms to incorporate more information on MFFs;

D. Revision of the monetary threshold for incident reporting (at § 191.3) to update for inflation over the three decades since the current monetary threshold was established, and introduce a new appendix A to part 191 to provide for annual updates to that threshold to account for inflation;

E. Revision of § 192.465 to clarify that operators may remotely inspect rectifier stations for external corrosion;

F. Revision of atmospheric corrosion monitoring requirements (at §§ 192.481, 192.491, 192.1007, and 192.1015) both to align the inspection interval for atmospheric corrosion on gas distribution service pipelines with leakage survey requirements at § 192.723, and to clarify that consideration of corrosion risks under DIMP explicitly includes atmospheric corrosion;

G. Revision of requirements governing plastic pipe (at §§ 192.7, 192.121, 192.281, 192.285, and appendix B to part 192) to improve alignment with, and incorporate by reference, certain updated industry standards;

H. Revision of test requirements for pressure vessels at § 192.153 to align pressure test factor requirements with industry standards, and to clarify certain other pressure testing requirements;

I. Revision of the welding process requirement at § 192.229 to align better with welder requalification requirement at § 192.229(d)(2); and

J. Revision of language at § 192.507 to extend an existing authorization for pre-testing of fabricated units and short segments of steel pipe prior to installation on pipelines with high-stress operating conditions to pipelines operating at lower-stress operating conditions.

C. Costs and Benefits

In accordance with 49 U.S.C. 60102, Executive Order (E.O.) 12866,[3] and DOT regulations at § 5.13(e), PHMSA has prepared an assessment of the costs and benefits of this final rule as well as reasonable alternatives. The amendments promulgated in this final rule are deregulatory, with the intention and effect of reducing regulatory burdens, increasing flexibility, improving efficiency, and adding clarity to existing rules without adversely affecting safety. PHMSA expects the incremental cost savings to accrue on an ongoing annual basis. PHMSA used a 20-year analysis period for this final rule. PHMSA estimates the total quantified annualized cost savings to be approximately $129.8 million (at a discount rate of 7 percent) or approximately $132.5 million (at a discount rate of 3 percent). Table-1 presents the estimated total cost savings for the 20-year period and the estimated

[1] 82 FR 45750 (Oct. 2, 2017).

[2] 85 FR 35240.

[3] ''Regulatory Planning and Review,'' 58 FR 51735 (Oct. 4, 1993).

annualized cost savings over the same period.

TABLE 1—TOTAL ESTIMATED DISCOUNTED COST SAVINGS
[2019 $ in millions]

Category	Estimated cost savings
Total (20 years; discounted at 7 percent)	$1,374.8
Total (20 years; discounted at 3 percent	1,971
Annualized (discounted at 7 percent)	129.8
Annualized (discounted at 3 percent)	132.5

PHMSA does not anticipate that the amendments will have an adverse impact on safety or a significant effect on the environment. The largest quantified cost savings are due to the PSR amendments related to farm taps and atmospheric corrosion discussed in sections III.A and III.F, respectively, of the preamble to this final rule. PHMSA expects other amendments to improve regulatory flexibility, clarity, and simplicity. Additional details regarding PHMSA's evaluation of the costs and benefits of this final rule are available in the Final Regulatory Impact Analysis (RIA) posted in the rulemaking docket.

II. Background

A. Regulatory Reform Executive Orders and Department Response

As explained at greater length in the NPRM,[4] DOT published a notice, ''Notification of Regulatory Review,'' on October 2, 2017,[5] requesting recommendations on existing DOT rules and other agency actions that could be eliminated without adversely affecting safety. DOT in particular solicited the public's assistance in identifying DOT regulations and other actions which eliminate jobs or inhibit job creation; are outdated, unnecessary, or ineffective; impose costs that exceed benefits; create a serious inconsistency or otherwise interfere with regulatory reform initiatives and policies; could be revised to use performance standards in lieu of design standards; or that potentially unnecessarily encumber energy production. After a 30-day comment period, DOT re-opened the comment period until December 1, 2017.[6] DOT received nearly 3,000 public comments. Approximately 30 pertained to the PSR.[7]

B. PHMSA Notice of Proposed Rulemaking

Consistent with DOT's regulatory reform efforts and informed by PSR-pertinent comments received in response to the DOT Notification of Regulatory Review discussed above, PHMSA's Office of Pipeline Safety (OPS) reviewed the PSR and identified unnecessary, outdated, and non-cost-justified regulatory requirements that could be repealed, replaced, or modified without adversely affecting safety. PHMSA also considered certain petitions for rulemaking and petitions for reconsideration of earlier PSR amendments.

On June 9, 2020, PHMSA published an NPRM[8] proposing several amendments to 49 CFR parts 191 and 192 to reduce regulatory burdens on operators of gas pipelines without adversely affecting safety. The comment period for the NPRM ended on August 10, 2020. PHMSA received 46 comments on the NPRM, including late-filed comments. PHMSA received comments from groups representing the regulated pipeline industry; groups representing various public interests, including environmental groups; State utility commissions and regulators; individual pipeline operators; and private citizens. PHMSA received late-filed comments from the National Association of State Pipeline Safety Representatives (NAPSR), the Gas Piping Technology Committee (GPTC), a coalition of several industry trade associations, and GPA Midstream.[9] PHMSA also had a conversation with a member of the Gas Pipeline Advisory Committee (GPAC) and representatives of the Pipeline Safety Trust (PST) after the end of the comment period; a summary of that meeting has been placed in the rulemaking docket. Consistent with §§ 5.13(i)(5) and 190.323, PHMSA considered the late-filed comments and materials because of their relevance to the rulemaking and the absence of additional expense or delay resulting from their consideration.

Some of the comments PHMSA received were beyond the scope of the amendments proposed in the NPRM. The issues raised in those comments may be the subject of other existing or future rulemaking proceedings.

The remaining comments reflect a wide variety of views on the merits of the proposed PSR amendments. PHMSA read and considered all the comments posted to the docket for this rulemaking. These comments and PHMSA's response to those comments are described in section III.

Contemporaneously with PHMSA's development of the NPRM, the President issued E.O. 13924, ''Regulatory Relief to Support Economic Recovery,''[10] directing Federal agencies to respond to the economic harm caused by the novel coronavirus by reviewing their regulations and considering taking appropriate action, consistent with applicable law, to temporarily or permanently rescind or modify those regulations to reduce regulatory burdens and thereby promote economic growth.[11] PHMSA understands the cost savings expected from this final rule to be consistent with E.O. 13924's mandate.

C. Gas Pipeline Advisory Committee Meeting

The Technical Pipeline Safety Standards Committee, commonly known as the Gas Pipeline Advisory Committee (GPAC; the committee), is an advisory committee mandated by statute (49 U.S.C. 60115) that advises PHMSA on proposed safety standards. The GPAC is one of two pipeline advisory committees that focus on technical safety standards that were established under the Federal Advisory Committee Act, as amended (5 U.S.C. App. 1–16). The GPAC consists of 15 members, with membership divided among Federal and State agencies, the natural gas industry,

[4] 85 FR 35241–42.

[5] 82 FR 45750.

[6] 82 FR 51178.

[7] Docket No. DOT–OST–2017–0069.

[8] 85 FR 35240.

[9] GPA, formerly the Gas Processors Association.

[10] 85 FR 31353 (May 22, 2020).

[11] E.O. 13924 at § 4.

and the public. The GPAC considers the ''technical feasibility, reasonableness, cost-effectiveness, and practicability'' of each proposed pipeline safety standard and provides PHMSA with recommended actions pertaining to those proposals.

The GPAC met in an online virtual meeting on October 7, 2020 to consider the regulatory proposals of the NPRM. The GPAC members discussed comments made on the NPRM. To assist the GPAC in its deliberations, PHMSA presented a description and summary of the proposals in the NPRM and the comments received on those issues. PHMSA also assisted the committee by fostering discussion, developing recommendations, and providing direction on which issues were most pressing. A transcript of the meeting and all presented materials is available in the docket for the rulemaking and on the web page PHMSA established for the meeting.[12]

The committee voted on the technical feasibility, reasonableness, cost-effectiveness, and practicability of each of the NPRM's provisions. In many instances, the committee recommended changes that the committee found would make certain proposals more feasible, reasonable, cost-effective, or practicable. These balloted recommendations and the transcript for the meeting serve as the GPAC's report pursuant to 49 U.S.C. 60115. These recommendations are discussed in section III of the preamble to this final rule for each of the topics proposed in the NPRM.

III. Analysis of Comments, GPAC Recommendations, and PHMSA's Response

The proposals in the NPRM, substantive comments received, as well as the GPAC's recommendations are organized by topic below and are discussed in the appropriate section with PHMSA's response to and resolution of those comments.

Distribution Integrity Management Program (DIMP)

On December 4, 2009, PHMSA issued a final rule titled, ''Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines.'' [13] The 2009 rule created 49 CFR part 192, subpart P, requiring gas distribution operators to develop and implement integrity management (IM) programs. The NPRM contained two proposed revisions to DIMP requirements to ease or eliminate regulatory burdens on certain gas distribution operators. The first revision is to allow operators of farm taps [14] connected to transmission or regulated gathering lines the option of managing maintenance of pressure regulating devices under either § 192.740 or their DIMP in accordance with subpart P. As part of this amendment, PHMSA also proposed to exempt farm taps originating from unregulated gathering and production pipelines from DIMP, § 192.740, and incident and annual reporting requirements in part 191. Second, the NPRM included a proposal to revise §§ 192.1003 and 192.1015 to exempt master meter operators from DIMP due to their simplicity. Master meter systems that serve fewer than 100 customers from a single source are currently required to comply with a simplified set of DIMP requirements detailed in § 192.1015.

A. Farm Taps (Sections 191.11, 192.740, 192.1003)

1. PHMSA's Proposal

In the NPRM, PHMSA proposed to revise §§ 192.740 and 192.1003 to give operators the choice to manage inspections of pressure regulators serving farm taps under either their DIMP or by following the inspection requirements at § 192.740.

On January 23, 2017, PHMSA published a final rule that added § 192.740, ''Pressure regulating, limiting, and overpressure protection—Individual service lines directly connected to production, gathering, or transmission pipelines.'' [15] Section 192.740 includes maintenance requirements for regulators and overpressure protection equipment for an individual service line that originates from a transmission, gathering, or production pipeline (*i.e.,* a farm tap). Currently, such devices must be inspected and tested at least once every 3 calendar years, with intervals not to exceed 39 months. The 2017 rule also revised the DIMP applicability regulations at § 192.1003 to exclude farm taps from DIMP requirements. The change was intended to create uniform compliance requirements for farm taps, address over-pressurization risks, and decrease the burden of meeting the DIMP requirements for transmission and gathering line operators who otherwise do not operate distribution assets. However, PHMSA had not considered that some farm taps are operated by local distribution companies rather than the operator of the transmission, gathering or production line itself. Operators who historically had included farm taps in their DIMP found it burdensome to remove those facilities from their plan and reevaluate the risks under a new, prescriptive program.

DOT received a comment in response to the Notification of Regulatory Review from the American Gas Association (AGA), the American Petroleum Institute (API), and Interstate Natural Gas Association of America (INGAA) (collectively, ''the Associations''), which recommended that PHMSA revise §§ 192.740 and 192.1003 to allow operators the flexibility to address the maintenance of farm taps under either of these regulatory requirements. After considering those comments, the NPRM proposed to revise §§ 192.740 and 192.1003 to exempt farm taps originating from transmission lines and regulated gathering lines from § 192.740 if they are included in a DIMP under subpart P. This provides operators the choice to manage the safety of farm tap regulators under either DIMP or the § 192.740 inspection requirement.

Finally, the NPRM included a proposal to exempt farm tap service lines connected to unregulated gathering or production pipelines from annual reporting (§ 191.11), farm tap regulator maintenance (§ 192.740), and DIMP (part 192, subpart P). Any portion of a farm tap that meets the definition of a service pipeline at § 192.3 must still comply with all other requirements in parts 191 and 192 applicable to service pipelines, even if the source of the service pipeline is not regulated by PHMSA. For example, an entity that operates a service line connected to a production pipeline must have an operator identification number in accordance with § 191.22 and must submit gas distribution incident reports for incidents that occur on the service line (§ 191.9). While the operator's production pipeline is exempt from part 191 (see § 191.1(b)(4)), any facility that meets the definition of a service line is a regulated distribution pipeline and therefore does not fall within the exemption for unregulated gathering and production pipelines.

2. Summary of Public Comments

Several commenters suggested PHMSA should simplify how farm tap requirements are presented in the PSR. The American Association of Laboratory

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[12] *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=151&nocache=4862.*

[13] 74 FR 63905.

[14] A ''farm tap'' is the common name for a pipeline directly connected to a gas transmission, production, or gathering pipeline that provides gas to a customer. The term farm tap is not defined in the PSR; however, portions of a farm tap upstream of either the outlet of the customer's meter or the connection to a customer's piping, whichever is further downstream, may be a service line regulated under part 192. See § 192.3 (definition of ''service line'').

[15] 82 FR 7972.

Accreditation (A2LA) recommend adding a provision requiring that those entities conducting inspections achieve and maintain ISO/IEC 17020 (Conformity Assessment-Requirements for the Operation of Various Types of Bodies Performing Inspection) accreditation. The FreedomWorks Foundation (FreedomWorks) commented that the proposed changes in the NPRM would especially benefit smaller operations burdened by the high cost of compliance upon startup. PST commented the proposed PSR amendments appear to demonstrate an equivalent level of safety and they do not oppose this change. One company provided an editorial suggestion that the last word in proposed § 192.740(c)(3) should be ''or'' to clarify that this section (§ 192.740) does not apply if any one of the listed conditions apply.

Several commenters commented on farm tap-related terms and definitions proposed in § 192.740. Sander Resources suggested there were at least two significant definitional issues contained within the proposed rule that confused farm tap operators. The first relates to ''unregulated . . . gathering.'' Sander Resources commented that, technically, there is no such thing as ''unregulated gathering.'' All gathering lines are subject to the jurisdiction of PHMSA, but some are exempted from the requirements of part 192 as specified in § 192.9. Thus, this reference could be interpreted to mean that all gathering lines are still subject to the requirements of § 192.740 or § 192.1003 and related provisions, which could encompass much of part 192. They recommended that PHMSA clarify what it means to be ''unregulated,'' possibly through a reference to whether a line is subject to regulation under § 192.9. The Gas Piping Technology Committee (GPTC) similarly suggested that PHMSA clarify that regulated and unregulated gathering lines are as determined in § 192.8.

Sander Resources (on behalf of the Independent Petroleum Association of America, or IPAA) also raised a concern related to the definition of ''service line'' and, in particular, language in the NPRM's preamble suggesting that the part 192-regulated ''service line'' portion of a farm tap would begin at the ''first aboveground point where downstream piping can be isolated from source piping (*e.g.,* a valve or regulator inlet).'' AGA, API, the American Public Gas Association (APGA), and INGAA (collectively, AGA *et al.*) jointly submitted a similar comment recommending against PHMSA defining the ''service line'' portion of a farm tap in the proposed amendment to § 192.740. They commented it is neither practicable nor necessary for safety to define a uniform starting point for the service line on every farm tap directly connected to a transmission line. Their preferred approach would be to incorporate a distribution center definition that allows farm tap piping to be classified as a distribution center and explicitly allow operators to designate piping as transmission, even if the pipeline could be classified as distribution under the existing § 192.3. Rather than defining where the ''service line'' starts for farm taps under part 192, TC Energy commented PHMSA should revise § 192.740 to apply to ''pipelines'' serving farm tap customers instead of ''service lines,'' and eliminate the description of the source of supply to the farm tap customer. TC Energy believes that these changes would maintain the intended protections to farm tap customers and address industry concerns. A private citizen similarly commented that, in addition to these clarifications, PHMSA should clarify the definitions for transmission lines and distribution centers.

GPA Midstream stated that they did not support the NPRM preamble statement that, on a farm tap, the boundary between source piping and the distribution service lines is the first aboveground isolation point downstream from the source piping. They stated that there is no legal basis for using that point to delineate where a source production, gathering, or transmission line ends and a gas distribution service line under part 192 begins in a farm tap configuration. GPA Midstream urged PHMSA to acknowledge in the final rule that an operator may exercise reasonable discretion in determining where source piping ends and distribution service line piping, if any, begins in farm tap configurations. The Independent Oil and Gas Association of West Virginia (IOGAWV) commented PHMSA should not attempt to use its authority to change private contracts by transferring the cost of complying with the PSR to producers and unregulated gathering line operators. IOGAWV and the Ohio Oil and Gas Association (OOGA) stated PHMSA should take this opportunity to exempt farm taps from the PSR. IPAA urged PHMSA to recognize the significant difference between privately-owned farm taps, governed by contract or statute, and true distribution systems. GPA Midstream reiterated concerns with the definition of the start of a service line and the applicability of part 192 to farm taps connected to production lines and unregulated gathering lines in supplemental comments submitted after the GPAC meeting.

The GPAC voted unanimously in favor of the PSR amendments proposed in the NPRM, provided that PHMSA remove § 192.740(c)(4), thus eliminating language implying where a service line starts on a farm tap.

3. PHMSA Response

The final rule adopts the amendments with respect to farm taps as proposed in the NPRM, but revises the proposed § 192.740 as discussed below. PHMSA determined that compliance with the pressure regulator inspection requirements in § 192.740 or compliance with DIMP provide an equivalent level of safety. DIMP does not include specific, prescriptive inspection requirements for pressure regulating devices; however, operators are required by § 192.1007 to evaluate risks due to equipment failure under DIMP, which includes pressure regulating devices. Accordingly, farm tap operators must consider overpressure risk due to regulator failure in their DIMP, especially if the source pipeline pressure is very high. While § 192.740 is focused on pressure regulator maintenance, DIMP is a broader safety program that requires operators identify, evaluate, rank, and mitigate a wide range of risks to pipeline safety. Either requirement provides safety to farm tap customers by reducing the probability of a regulator system malfunction and, in the case of DIMP, incidents caused by other threats such as excavation damage and corrosion. Therefore, this change provides greater flexibility for operators of these farm taps while still requiring that operators evaluate all equipment to protect against failures and protect human health and the physical environment.

This proposed amendment was intended to provide flexibility for farm tap operators. It was not designed to resolve more general definitional questions surrounding the topic of farm taps. Therefore, PHMSA agrees with the suggestion to remove the proposed § 192.740(c)(4) from the final rule, which implied where the source piping on a farm tap ends and distribution, transmission, or customer piping begins. PHMSA believes that this change resolves most of the concerns about definitional changes raised by commenters. To the extent that there are remaining questions surrounding farm taps following this rulemaking, PHMSA will use ongoing efforts such as the proposed Farm Taps Frequently Asked

Questions (FAQs); [16] the remaining rulemaking projects associated with the Safety of Gas Transmission and Gas Gathering Pipelines NPRM; [17] and, if necessary, additional rulemaking and guidance. While the comment from TC Energy sidesteps these definitional issues, and has the benefit of extending protection to farm taps that operate at greater than 20 percent of specified minimum yield strength (SMYS) (and are therefore classified as transmission lines rather than service lines pursuant to the definition of a transmission line in § 192.3), it requires defining an additional term (''farm tap customer'') which was not made available for public comment in the NPRM or discussed by other comments in the rulemaking docket.

While this final rule does not define the boundaries of that portion of a farm tap that is regulated as a service line under part 192, the fact that a farm tap may include a regulated service line remains unchanged. Therefore, PHMSA disagrees with comments that the NPRM's characterization of portions of farm taps as jurisdictional service lines creates ''entirely new'' legal obligations for operators of service lines who also operate non-jurisdictional production lines and rural gathering lines that are not subject to safety regulation under part 192. Removing farm taps connected to production lines and unregulated gathering lines from the scope of the entire PSR, as suggested by some commenters, would be a consequential change from longstanding regulatory application and is beyond the scope of this final rule.

PHMSA and its predecessor agencies have been explicit and consistent with respect to the applicability of the part 192 regulations to distribution service lines in farm tap applications since the earliest years of Federal gas pipeline safety oversight. The Office of Pipeline Safety revised the definition of a service line in § 192.3 to clarify the point at which a service line ends and customer piping begins in an NPRM entitled, ''Minimum Federal Safety Standards for Transportation of Natural and Other Gas by Pipeline: Definition of Service Line,'' published on April 10, 1971.[18] On April 10, 1973, PHMSA finalized the proposal and defined the downstream end of a service line as the customer meter or connection to customer piping, whichever is further downstream.[19] This boundary stands with minor clarifications to this day at § 192.3. PHMSA formulated the definition of ''service line'' to address service lines in farm tap applications and other situations where no meter is present. PHMSA's predecessor agency, the Research and Special Programs Administration, again acknowledged the regulated status of service lines in farm tap applications in a final rule titled, ''Pipeline Safety: Customer-Owned Service Lines'' issued on August 14, 1995.[20] Finally, providing gas to farm tap customers is not a defined gathering or production function in either § 192.3 or in API Recommended Practice (RP) 80 (incorporated by reference in § 192.7). While production pipelines and some gathering pipelines are not subject to safety regulation under part 192, the distribution of national gas to customers is subject to PHMSA jurisdiction (49 U.S.C. 60101(a)(21)(i)) and the applicability of part 192 (§§ 192.1(a), 192.3) regardless of other activities in which an operator may also be engaged.

Regarding operators' concerns about their responsibility for customer-owned piping that they do not own or have access to, PHMSA reiterates that the final rule imposes no new requirements on operators of service lines in farm tap applications. Section 192.3 provides that a service line ends at the connection to customer-owned piping, or the outlet of the meter, whichever is further downstream. In the preamble to the 1995 customer-owned service line rule described above, PHMSA explained that that the PSR applies to the distribution of gas up to the end of a pipeline operator's service line.[21] In an earlier interpretation, PHMSA also noted that customer piping downstream of the end of a service line as defined in § 192.3 is not subject to part 192, provided the gas is for the customer's own use.[22] Therefore, the PSR does not require the source pipeline operator to maintain customer-owned piping downstream of the customer meter as defined in § 192.3. If there is no customer meter, then the service line terminates at the connection to customer-owned piping. Some operators do maintain customer piping voluntarily or as required by State, local, or contractual requirements. If an operator of a service line does not maintain the customer's piping under such arrangement, then the customer notification requirements in § 192.16 may apply.

PHMSA agrees with certain comments to clarify language in § 192.740. In the final rule, PHMSA has replaced the term ''unregulated gathering line'' with a gathering line other than a regulated gathering line as determined in § 192.8. In other words, a gathering line as determined in accordance with § 192.8 and API RP 80, but excluding a Type A or Type B regulated gathering line as defined in § 192.8. In addition, the exceptions in paragraph (c) are now separated by an ''or'' in the final rule.

Lastly, because the PSR revisions adopted in this final rule obviate the need for its March 29, 2019 ''Exercise of Enforcement Discretion Regarding Farm Taps,'' [23] PHMSA withdraws that document as of the effective date of this final rule.

B. Master Meter Operators (Sections 192.1003, 192.1005, 192.1015)

1. PHMSA's Proposal

In the NPRM, PHMSA proposed to revise §§ 192.1003, 192.1005, and 192.1015 to exempt master meter operators from DIMP requirements. A ''master meter system'' is defined at § 191.3 as a pipeline system for distributing gas where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. Examples of master meter systems include owners of apartment complexes or mobile home parks who provide or sell gas to tenants. Unlike most gas distribution operators, delivering gas is typically not a master meter operator's primary business.

When DIMP requirements were first proposed in 2008,[24] PHMSA recognized that master meter systems tend to be operated by small entities with simple systems compared to normal gas distribution operators. Section 192.1015 was intended to provide a simplified set of DIMP requirements that master meter operators could easily implement and that would enhance safety. However, PHMSA has determined that Section 192.1015 requirements are neither easily implemented nor do they enhance safety. Master meter operators have struggled to implement the relatively simple master meter systems DIMP requirements that were designed for

[16] 85 FR 21820 (Apr. 20, 2020).

[17] RINs 2137–AF39 (Pipeline Safety: Safety of Gas Gathering Pipelines) and 2137–AF38 (Pipeline Safety: Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments), associated with PHMSA, ''Notice of Proposed Rulemaking: ''Pipeline Safety—Safety of Gas Transmission and Gathering Pipelines,'' 81 FR 20721 (Apr. 8, 2016).

[18] 36 FR 9667.

[19] 38 FR 9083.

[20] 60 FR 41821.

[21] 60 FR 41821.

[22] PHMSA Interpretation #PI–73–0110 (June 6, 1973), *https://cms7.phmsa.dot.gov/regulations/title49/interp/PI-73-0110.*

[23] 84 FR 11253.

[24] PHMSA, ''Notice of Proposed Rulemaking: Integrity Management Program for Gas Distribution Pipelines,'' 73 FR 36015 (June 25, 2008) (DIMP NPRM).

complex gas distribution systems. In addition, PHMSA determined that there is no safety benefit from applying even that limited set of DIMP requirements to master meter systems, as compliance with other applicable pipeline safety regulations in part 192 provides robust assurance of public safety. The applicable part 192 requirements that PHMSA considered include, but are not limited to, operations and maintenance requirements at subpart L and subpart M, continuing surveillance requirements at § 192.613, and the failure investigation requirement at § 192.617.

2. Summary of Public Comments

Several commenters generally supported exempting master meter operators from the DIMP requirements in part 192. These commenters (including the National Propane Gas Association (NPGA), the National Association of Pipeline Safety Representatives (NAPSR), AmeriGas, and Superior Plus Propane (SPP)) agreed with PHMSA's characterization of master meter systems as generally small, simple systems that see little benefit from DIMP compliance. These commenters agreed that compliance with existing subparts A through N of part 192 is sufficient to ensure the safety of small, simple master meter systems. They asserted that the current requirement of subpart P to create a DIMP, even using the SHRIMP tool,[25] consumes significant additional time and resources with little or no safety benefit, noting that the result of the process for master meter systems is typically a determination that there is no need for additional mitigating actions on any portion of the pipeline system. As a result, the commenters stated that the time and resources expended to comply with the DIMP requirements have no meaningful safety benefits for such systems. The PST commented that they do not oppose this change, but urged PHMSA and its State partners to ensure that master meter operators are managing the integrity risks to their systems outside the context of a DIMP.

PHMSA also received comments concerning similar DIMP requirements for small liquefied petroleum gas (LPG) distribution pipeline systems. A ''small LPG operator'' is defined in § 192.1001 as a liquefied petroleum gas distribution system that serves fewer than 100 customers from a single source. Small LPG operators are currently required to comply with the same DIMP requirements as master meter systems. Several commenters (including NPGA, NAPSR, AmeriGas, and SPP) commented that jurisdictional propane pipeline systems are like master meter systems and therefore small LPG operators should be exempt from the DIMP requirements as well. They commented that small LPG systems are comparable to master meter systems in size and application. Like master meter systems, the commenters claimed the majority of small LPG pipeline systems are single-property systems that occupy a small overall footprint in size, generally operate at a single operating pressure, and have no equipment other than pipe, meters, regulators, and valves. They commented that small LPG systems typically serve 25 customers or less, and facilities such as those at RV parks or strip malls can have as few as three customers; very few small LPG systems serve more than 100 customers. One anonymous commenter associated with an LPG system stated that the DIMP process is lengthy and unnecessary, and that in their experience, many of the prompts on the DIMP form [26] do not make sense given the layout of a small LPG utility. NAPSR stated that many of these smaller systems identify only third-party damage as a major threat to the system, and a DIMP requires a considerable amount of work for a very small amount of safety benefit.

Commenters representing LPG suppliers (including AmeriGas, SPP, and NPGA) noted that with regard to the PSR, the regulated entity is the entity that owns the pipeline and receives the operator ID issued by PHMSA for that pipeline system. They stated that in many cases, the LPG supplier does not operate the pipeline and their primary business is to transport gas by delivery truck, not pipelines. They further stated that most are contractors to the entity that owns the pipeline and the pipeline operator ID for the system. They stated that many of these master meter operators use contractors for service, but those contractors are not the operators under part 192. These commenters agreed that the other part 192 requirements continue to apply to provide adequate requirements for small LPG systems in the absence of DIMP requirements. They also stated that in addition to the requirements in part 192 applicable to all gas distribution pipelines, § 192.11 requires LPG distribution systems to comply with a National Fire Protection Association (NFPA) standard, NFPA 58 (LP-Gas Code) or NFPA 59 (Utility LP-Gas Plant Code), which contains comparable and supplemental provisions that address safety. They asserted that the additional requirements of DIMP do not add a measure of safety beyond the provisions in part 192 and NFPA 58.

AmeriGas and NPGA estimated that extending the NPRM's proposed DIMP exemptions for master meters to small LPG systems could result in $1.12 million in annualized cost savings; this estimate was calculated by applying the cost estimates in the RIA to an estimate of the number of small LPG operators in *Safety Regulation for Small LPG Distribution Systems,* a report published in 2018 by the Transportation Research Board (TRB).[27] The commenters asserted that these additional savings would further PHMSA's goal of reducing regulatory impact burdens. The commenters also stated that these estimated savings to the industry would allow small LPG operators to devote more of their resources in other areas of safety.

NAPSR suggested that small distribution utilities with 100 or fewer customers should also be exempted from the DIMP requirements, stating that many master meter systems, small distribution systems and small LPG systems typically have no threats beyond the minimum threats listed in § 192.1015(b)(2).

The GPAC voted unanimously in favor of PHMSA's proposed amendment with respect to the applicability of DIMP requirements to master meter systems. The GPAC did not recommend changes to DIMP requirements for small LPG systems or small distribution systems.

3. PHMSA Response

The final rule revises §§ 192.1003, 192.1005, and 192.1015 to eliminate DIMP requirements for master meter systems as proposed in the NPRM. Through inspections, PHMSA and its State partners have seen that master meter operators have had significant difficulties implementing these simplified DIMP requirements effectively. PHMSA's State-Federal DIMP team has noted that a significant amount of State inspection and operator maintenance effort was being used to improve DIMP compliance among master meter operators. Despite these

[25] The ''Simple, Handy, Risk-based Integrity Management Plan'' tool published by the APGA Security and Integrity Foundation.

[26] PHMSA Gas Distribution Integrity Assessment Question Set, *available at https://www.phmsa.dot.gov/forms/phmsa-gas-distribution-ia-question-set-pdf.*

[27] TRB, *Transportation Research Board Special Report 327: Safety Regulation for Small LPG Distribution Systems* (2018), *https://www.nap.edu/catalog/25245/safety-regulation-for-small-lpg-distribution-systems.*

efforts, inspection data voluntarily submitted by some States shows that approximately half of master meter operators inspected between 2014 and 2017 did not have an acceptable DIMP in place before the compliance deadline of August 2, 2011, and for any given requirement 10–20% of master meter operators were not in compliance. PHMSA believes that this effort may be better used to implement other part 192 safety requirements effectively that master meter system operators will remain obliged to follow.

Even when properly implemented, DIMP principles that are effective for larger operators do not have the same value for comparatively simple master meter systems within a limited geographical area. The DIMP NPRM noted that master meter systems often include only one type of pipe, a single operating pressure, and no equipment other than pipe, meters, regulators, and valves. For these small and simple systems, a comprehensive management system like DIMP is not required to integrate data and information to identify risk mitigation strategies and actions. PHMSA's experience indicates that the analysis and documentation requirements of DIMP have had little safety benefit for this type of operator. And, anecdotally, PHMSA and State enforcement personnel have advised that focusing on more fundamental risk mitigation activities (particularly those required by §§ 192.605 (*Procedural manual for operations, maintenance, and emergencies*), 192.613 (*Continuing surveillance*), and 192.617 (*Investigations of failures*)) yields more safety benefits than implementing a DIMP for this class of operators. Due to the implementation issues identified by PHMSA and State inspectors, PHMSA expects that exempting master meter operators from subpart P would result in cost savings for master meter operators without negatively impacting safety. Considering the burden on finite State inspection resources, implementation difficulties, and the limited safety benefits of DIMP compliance for master meter systems described above, PHMSA believes there could even be potential safety benefits because operators and inspectors can prioritize more pertinent compliance activities specific to master meter systems.

PHMSA appreciates the comments regarding the applicability of DIMP towards small LPG operators and acknowledges that many small LPG systems have configurations like master meter systems. However, PHMSA believes that the decision about whether to extend the DIMP exception to such facilities or to all distribution systems with fewer than 100 customers would benefit from additional safety analysis and notice and comment procedures prior to further consideration. In 2018, the TRB published a report on Federal safety standard for small LPG systems. The TRB's recommendations focused on clarifying the definition of a ''public place'' and improving State inspection programs. While the TRB suggested that a PHMSA-supervised State waiver process could be appropriate, it did not recommend exempting all small LPG systems from DIMP or any other requirement. PHMSA will continue to evaluate the issue of DIMP requirements for small LPG systems and, if appropriate, propose changes in a future rulemaking giving due consideration to the public comments on the NPRM, the recommendations of the GPAC, and the TRB report. For similar reasons, PHMSA has also not adopted suggestions from commenters to exempt other distribution operators with fewer than 100 customers.

Reporting and Information Collections

C. Mechanical Fitting Failure Reporting (Sections 191.12, 192.1009)

1. PHMSA's Proposal

On February 1, 2011, PHMSA issued the final rule, ''Pipeline Safety: Mechanical Fitting Failure Reporting Requirements'' [28] adding §§ 191.12, 192.1001, and 192.1009 to the PSR. Section 191.12 sets forth the requirement for operators to report mechanical fitting failures (MFFs) through DOT Form PHMSA F–7100.1–2 (MFF report form). Section 192.1001 defines a ''mechanical fitting.'' Section 192.1009 requires distribution pipeline operators to submit a MFF report to PHMSA almost every time there is a release from a mechanical joint, the majority of which are low-consequence or no-consequence events that do not meet the definition of an incident at § 191.3. These requirements expanded an earlier requirement established in the December 4, 2009 DIMP final rule that was limited to mechanical couplings used to join plastic pipe.[29] The DIMP final rule adopted the MFF report requirement as a result of investigations of incidents caused by poorly designed or improperly installed mechanical joints throughout the pipeline industry. PHMSA initially sought to collect these data in 2011 to determine the frequency of mechanical joint failures and identify the most common characteristics of those failures.[30] The 2009 DIMP final rule was part of a broader effort by PHMSA and the gas distribution pipeline industry to identify potential safety issues with plastic gas pipelines.

Like the Gas Distribution Incident Report form,[31] the MFF report form requires operators submit information on the design and installation of the failed fitting and the apparent cause of the failure. The MFF report form also includes manufacturing information; however, this is generally not known by the operator and therefore is reported as ''unknown.'' MFF reports are required for any failure of a mechanical joint other than those that result in a ''non-hazardous leak,'' as opposed to Gas Distribution Incident Reports, which are required only for events that meet the criteria for reportable ''incidents'' in § 191.3. Operators report any ''hazardous leak'' as that term is defined at § 192.1001. The criteria for a ''hazardous leak'' does not depend on an outcome severity threshold. Approximately 15,000 MFF reports are submitted to PHMSA each year, compared to approximately 100 Gas Distribution Incident Reports due to all causes. PHMSA publishes a report on the information collected and its analysis of the information received annually, which is available online.[32]

PHMSA determined that further collection of MFF reports has limited value, and proposed to remove §§ 191.12 and 192.1009, eliminating the requirement for operators to submit MFF reports through DOT Form PHMSA F–7100.1–2. PHMSA understands from analyzing MFF report forms received over the last decade that the purposes of this reporting requirement have been realized: PHMSA's analysis of data from MFF reports confirmed its expectations regarding MFF characteristics and causes, and pipeline operators have become much more sensitive to MFFs.

PHMSA considered that operators would still be required to submit incident reports via a modified version of the Gas Distribution Incident Report form (which would include most of the information on the MFF report form) for releases from mechanical fittings that meet the definition of an incident at § 191.3. Part G5–5 of the Gas Distribution Incident Report form currently requires operators to identify the MFF report number for incidents involving an MFF; PHMSA therefore proposed to replace this cross-reference

[28] 76 FR 5494.

[29] 74 FR 63905.

[30] 76 FR 5495.

[31] DOT Form PHMSA F 7100.1.

[32] *https://www.phmsa.dot.gov/pipeline/gas-distribution-integrity-management/dimp-performance-measures-data-analysis-procedure-report.*

with the fitting, manufacturer, and failure information that is currently collected on the MFF report form. PHMSA also proposed to revise the Gas Distribution Annual Report form [33] to include a count of hazardous leaks involving a mechanical joint failure. This issue was raised in comments submitted in response to the DOT Notification of Regulatory Review from the Associations, the Gas Piping Technology Committee (GPTC), and the West Virginia Oil and Natural Gas Association (WVONGA), which identified the MFF reporting requirement as an unnecessary and burdensome information collection.

2. Summary of Public Comments

Several commenters (including AmeriGas, NPGA, SPP, Dresser Natural Gas Solutions, the Norton McMurray Manufacturing Company (NORMAC), Oleksa and Associates, the Plastics Pipe Institute (PPI), and a private citizen) supported eliminating the MFF reporting requirement. Dresser contended that PHMSA has found these data do not provide meaningful trends related to risk of pipeline leaks. PPI stated that the removal of this regulatory reporting burden reduces the unnecessary focus on mechanical fittings as a potential source of incidents. NORMAC agreed that MFF reporting has not provided statistically significant trends or information upon which operators or regulators can act.

Several commenters (including AmeriGas, SPP, and NPGA) expressed concerns regarding PHMSA's proposal to modify the Gas Distribution Annual Report form to collect data on the number of mechanical joint failures. Those commenters opposed including a count of leaks involving mechanical joints on the Gas Distribution Annual Report form, noting that if limited value was derived from independent MFF reporting, it is reasonable to conclude that there would be limited value in tracking and reporting the number of MFFs on revised Gas Distribution Annual and Incident Report forms. NORMAC commented that part C of the current Gas Distribution Annual Report form requires each operator to report the total number of leaks and how many were classified as hazardous based upon the cause of the leak. The instructions provided for completion of part C describe each classification of cause in detail in terms of what is being requested of an operator. NORMAC noted that modifying the Gas Distribution Annual Report form as proposed will lead the user to jump to the conclusion that any leak involving a mechanical joint arises from the mechanical fitting being ''faulty,'' when the leak may be caused by improper installation by the operator and should therefore be coded as caused by ''Incorrect Operation.'' GPTC commented that reporting leaks caused by mechanical joint failure would repeat reporting of leaks caused by ''pipe, weld, or joint failure'' and potentially be confusing for operators. They further commented that the leak information is intended to be general in nature and not intended to capture the ''laboratory analysis'' for eliminated leaks.

Regarding the proposed changes to Gas Distribution Incident Report form, NORMAC expressed concerns with the NPRM's proposal to incorporate existing data fields in the current MFF report within part G (Apparent Cause), sub-cause G5 (Pipe, Weld, or Joint Failure) of a revised Gas Distribution Incident Report form. NORMAC noted that the cause of a failure may not be due to Pipe, Weld, or Joint Failure. Specifically, they noted that fittings that fail due to improper installation are required to be categorized under the ''Incorrect Operation'' cause. NORMAC also mentioned that Question 12 under sub-cause G5 (Pipe, Weld, or Joint Failure) duplicate what sub-cause G7 (Incorrect Operation) is asking. NORMAC stated that requiring respondents to answer the same question under two categories will lead to confusion and make effective analysis of the resulting database difficult. NORMAC submitted text revisions to sub-cause G5 of the Gas Distribution Incident Report form and associated instructions.

Dresser raised similar concerns with both the Gas Distribution Annual Report and the Gas Distribution Incident Report forms, in addition to noting that there could be confusion concerning the difference between a mechanical fitting and a mechanical joint. Dresser noted that the existing categories support the reporting of pipeline failures where mechanical fittings may be involved under the existing categories of ''Weld Pipe or Joint Failure'' or ''Incorrect Operation'' depending on the causal factors being a manufacturing or design defect for the former or a deficiency in the field installation practice or improper application for the latter. NORMAC also supported addressing the distinction between ''mechanical fitting'' and ''joint'' to ensure that the regulatory oversight activity focus on joints, the making of joints, and the qualifying of joining procedures.

Theresa Pugh Consulting commented that PHMSA should revise the Gas Distribution Incident Report form to include whether industrial and power sector customers were notified of a curtailment in gas supply following an incident and the duration of such disruption. The commenter stated the form should allow the operator to state if gas supply was maintained by re-directing natural gas at full contracted capacity to the customer through reverse flow or through alternative parties. The commenter noted that the power and industrial customers would benefit from a way to determine during contract negotiations whether the company they wish to purchase gas from has a sound and reliable safety program, but acknowledged challenges with ensuring that such information is not in a format that could be used by competitors to reverse engineer operational information about industrial customers such as plastics manufacturing plants. The commenter recommended that PHMSA should expand rather than shrink the reporting measures on its reporting forms.

NORMAC commented that burden on operators can be drastically reduced beyond what the proposed rulemaking proposes by also eliminating the portion of Plastic Pipe Database Collection (PPDC) reporting conducted by the American Gas Association that deals with mechanical joints. NORMAC commented that the PPDC is nearly identical to the MFF and has also not shown useful trends. NORMAC also asserted that recording and reporting mechanical joint leaks through PPDC is not as effective as addressing the problem directly within each operator's IM program. NORMAC suggested that PHMSA propose the discontinuation of this reporting effort in its role as PPDC chair.

PST opposed eliminating the MFF report requirement. They questioned whether this would prevent PHMSA from becoming aware of thousands of MFFs per year, many of which result in hazardous and potentially explosive leaks, others of which result in non-explosive but hazardous leaks of methane into the atmosphere. The commenter stated these circumstances would also not typically be reported as a safety-related condition, because of the many exemptions and exceptions to the safety-related condition reports listed in § 191.23(b). PST asserted the detailed information on MFFs is currently gathered so that PHMSA can identify any patterns among those failures, either by geography or failure type or any other common parameter. Limiting the detailed reporting in the MFF report to reportable incidents eliminates another source of

[33] DOT Form PHMSA F 7100.1–1.

information of leading indicators of problems common among operators, one that nets information on 15,000 fitting failures each year.

The GPAC voted 13–2 in favor of PHMSA's proposed amendment to eliminate the MFF reporting requirement. PST and the Environmental Defense Fund (EDF) voted against the proposed amendment. During the GPAC discussions, PST reiterated its reservations regarding reducing the availability to PHMSA and other safety regulators of information on hazardous leaks. PST also opined that eliminating MFF reporting may reduce operators' incentives to improve mechanical fitting performance. EDF, meanwhile, contended that the MFF report data being eliminated could prove helpful to Federal and State environmental regulators and public service commissions in evaluating the significance of methane emissions from service line couplings.

3. PHMSA Response

In the final rule, PHMSA is adopting the amendments to MFF reporting requirements at §§ 191.12 and 192.1001 as proposed in the NPRM. PHMSA is also retaining the proposed requirement to include a count of MFFs on the Gas Distribution Annual Report form and revision of the Gas Distribution Incident Report form to include information from the MFF report for incidents involving a failure of a mechanical joint.

PHMSA's 2018 analysis of MFF data reports obtained to date confirm PHMSA's expectations regarding the frequency and characteristics (including material, type, location, and vintage of fittings) of MFFs when it began this information collection activity under the DIMP final rule.[34] The 2018 analysis further notes that the MFF reports submitted in the preceding year show similar trends to the previous 5 years, and that all changes were within the expected variance. These findings mirror the conclusions of PHMSA's earlier, 2016 analysis of the MFF reports submitted in the then-preceding 5 years (2011–2015).[35] Because MFF report data reviewed in 2018 and 2016 confirmed PHMSA's expectations regarding the frequency and characteristics of mechanical joint failure without yielding new statistically significant causal or predictive insights, PHMSA has determined that additional information collection via a dedicated MFF report form is unnecessary.

PHMSA further notes improvements in fitting design, operator joining practices, and Federal safety requirements since the introduction of the MFF reporting requirement have improved the safety of mechanical fittings on newer installations. PHMSA's 2018 analysis of MFF report data reached a similar conclusion, noting that many operator DIMPs are sensitive to the risk of MFF following the introduction of the MFF reporting requirement. However, PHMSA's 2018 analysis notes that the number of operators submitting MFF reports has stayed approximately the same for the last several years—suggesting that any action-forcing benefit hypothesized has been realized and that the benefits from continuing a dedicated MFF reporting requirement may be negligible.

The modifications to other reports adopted in this final rule will help PHMSA ensure continued availability of information needed to provide effective regulatory oversight of MFFs. Leaks from mechanical joints are already aggregated within the broader categories on the existing Gas Distribution Annual Report form. The revised Gas Distribution Annual Report form requires reporting the number of leaks involving mechanical joint failures in addition to the existing, aggregated categories. This change is expected to provide sufficient information to track the safety performance of mechanical joints over time, among operators, or across the industry. These data are expected to provide operators, PHMSA, and State inspectors sufficient information to identify if action is needed under DIMP or other elements of operator programs for compliance with part 192 requirements.

PHMSA is also revising the Gas Distribution Annual Report form to identify the number of leaks involving a mechanical joint failure as a separate line item from the count of leaks by cause. However, to address the potential confusion raised by commenters, PHMSA will revise the proposed part C of the Gas Distribution Annual Report form to clarify that operators should report the number of hazardous leaks "involving" a mechanical joint failure, rather than "caused" by a mechanical joint failure. This aligns with the language in the current MFF report requirement and is clearer. PHMSA will further clarify in the form instructions that the count of leaks involving a mechanical joint failure is separate and in addition to the leaks by cause. Operators should continue to report all leaks by cause in the table in part C of the Gas Distribution Annual Report form as they have been doing previously, while the new count at the end of part C consists of a count of hazardous leaks involving the failure of a mechanical joint regardless of whether the leak was caused by equipment failure, incorrect operation/installation, or other causes. Likewise, on the Gas Distribution Incident Report form, operators should continue to report incidents involving a failure of a mechanical joint that was caused by improper installation under the "incorrect operation" cause under section G7 of the Gas Distribution Incident Report form. The revised Gas Distribution Incident Report form will not require operators to submit design and manufacturing information about incidents involving mechanical joints that were caused by incorrect operation rather than material, weld, or equipment failure.

PHMSA appreciates the concerns raised by commenters and members of the GPAC about reducing the data available to PHMSA and other stakeholders through changes in reporting requirements proposed in the NPRM and adopted in this final rule. PHMSA agrees that access to quality safety-related information is critical to implementation of an effective regulatory and enforcement program. However, these safety programs benefit from the flexibility both to create targeted information collection activities to address safety issues and to remove those information collection activities that are no longer necessary or have not proven useful. Here, PHMSA has determined that its original purpose for introducing a dedicated MFF reporting requirement has been satisfied. Although PHMSA could posit new justifications (*e.g.,* use by environmental regulators and utility commissions in calibrating regulatory oversight of service line couplings) for this dedicated reporting requirement, it declines to do so in this rulemaking. Nevertheless, PHMSA submits that Federal and State regulators' oversight activities may continue to benefit from nearly a decade of historical, granular data obtained from MFF reports,[36] in addition to the operator-specific MFF data that PHMSA will collect in the Gas

[34] PHMSA, *Analysis of Data from Required Reporting of Mechanical Fitting Failures that Result in a Hazardous Leak (§ 192.1009)* at 47–48 (Jul. 4, 2018), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-distribution-integrity-management/66046/mffr-data-analysis-procedure-2017-data-report-final-07-04-2018.pdf.*

[35] PHMSA, *Analysis of Data from Required Reporting of Mechanical Fitting Failures that Result in a Hazardous Leaks* (§ 192.1009) (Oct. 15, 2016).

[36] PHMSA makes such raw data available on its website at *https://www.phmsa.dot.gov/data-and-statistics/pipeline/mechanical-fitting-failure-data-gas-distribution-operators.*

Distribution Annual and Incident Report forms modified by this final rule.

Replacing the full MFF report with a count of MFFs on the Gas Distribution Annual Report results in a reduction in reporting burden for each event but without a significant loss of useful information to operators and PHMSA. Although the revised requirements eliminate the detailed information on each mechanical fitting failure, this information has not yielded meaningful new causal or predictive insights regarding leaks involving mechanical joints. On the other hand, the general count of leaks involving a mechanical joint failure as required in the revised Gas Distribution Annual Report is not burdensome to compile yet provides information on the relative safety performance of mechanical joints in general. This information remains valuable to PHMSA and State agencies for safety performance monitoring and for prioritizing inspections. PHMSA has determined that incident reporting requirements via a revised Gas Distribution Incident Report form and the revision to the Gas Distribution Annual Report form to include a count of hazardous leaks involving a mechanical joint failure is sufficient to identify the total number of hazardous leaks involving mechanical joint failures and identify trends over time and among States or operators.

Nor does this change absolve operators of other safety requirements that apply when leaks at MFFs are discovered. PHMSA requires that gas pipeline operators have procedures for investigating failures under § 192.617 to determine the causes of the failure and minimize the possibility of a recurrence. PHMSA also requires operators repair hazardous leaks promptly under § 192.703. These requirements apply regardless of whether the failure results in a reportable leak or incident. Finally, operators are required to consider leak history under the continuing surveillance requirements at § 192.613 and under their DIMP (§ 192.1007(b), (d), and (e)). PHMSA accordingly finds that the PSR change adopted in this final rule eliminates an unnecessary reporting burden without an adverse impact on safety.

Many of the comments received pertained to related topics on the Gas Distribution Incident and Annual Report forms and are not directly related to the reporting of mechanical joint failures. PHMSA will consider these comments during periodic updates and renewals of these information collections pursuant to the Paperwork Reduction Act. PHMSA does not have authority over voluntary information collection organized by other, non-governmental entities and therefore the comment related to data collected by the AGA through the PPDC is outside the scope of the NPRM. However, PHMSA will consider raising with other members of the PPDC whether its reporting protocols for MFFs should be modified.

D. Monetary Threshold for Incident Reporting (Section 191.3, New Appendix A to Part 191)

1. PHMSA's Proposal

On May 3, 1984, PHMSA's predecessor agency, the Research and Special Programs Administration, added a definition for an ''incident'' at § 191.3.[37] The definition provides criteria that requires operators to report specific events to PHMSA. The 1984 definition of an incident consists of a release of gas that, among other things, results in estimated property damage of $50,000 or more. That monetary threshold includes losses to the operator and third parties but excludes the cost of any lost gas. Today, over 30 years later, operators must still notify the National Response Center (§ 191.5) and submit an incident report to PHMSA (§§ 191.9 and 191.15) for any release that results in estimated property damage to the operator or third parties of $50,000 or more.

Multiple comments submitted in response to the DOT Notification of Regulatory Review addressed the $50,000 monetary damage threshold for reporting gas pipeline incidents. The Associations, GPTC, and GPA Midstream submitted comments recommending an increase in the monetary damage threshold for reporting gas pipeline incidents. Based on the average annual Consumer Price Index (CPI) from the Bureau of Labor Statistics of the U.S. Department of Labor, $50,000 in 1984 is $122,000 in 2019 dollars.[38] The current damage threshold requires incidents that would not have been reported in 1984 to be reported to PHMSA due to inflation in property, equipment, and repair costs.

PHMSA proposed in the NPRM to raise the reporting threshold for incidents that result in property damage to $122,000, consistent with inflation since 1984. The property damage criterion will continue to include losses to the operator and others but exclude the cost of lost gas. PHMSA did not propose any changes to the other criteria in the § 191.3 definition of an incident. The NPRM stated that PHMSA intended to base any finalized version of this provision on the price level at the time of publication of a final rule. PHMSA also requested comment on whether the level of safety information needed from property damage-only incident reporting should be updated to align with inflation, and the extent to which retaining a de facto annually-decreasing threshold after inflation would provide beneficial information on contributing risk factors and incident trends.

The NPRM also stated that PHMSA intends to update the monetary damage threshold on a regular basis in the future, potentially biennially. Future updates would be based on the same formula used for this adjustment:

$$T_n = T_p \times \frac{CPI_n}{CPI_p}$$

Where T_n is the revised damage threshold, T_p is the previous damage threshold, CPI_n is the average CPI–U for the preceding calendar year, and CPI_p is the average CPI–U used for the previous damage threshold. PHMSA could subsequently update the monetary damage threshold in accordance with this formula either through notice and comment rulemaking, a direct final rule, notice on the PHMSA public website, or other means. This method is similar to the method that the Federal Railroad Administration (FRA) implemented to update the criteria for reporting accidents/incidents at 49 CFR 225.19 and appendix B to part 225.[39]

2. Summary of Public Comments

Several commenters (including AGA *et al.,* AmeriGas, the Arkansas Independent Producers and Royalty Owners (AIPRO), GPA Midstream, NPGA, Paiute, the GPTC and SPP) expressed support for PHMSA's proposal to update the threshold for property damage in the definition of an incident to account for inflation. AGA, API, APGA, GPA Midstream, and INGAA reiterated their support for this proposal in supplemental comments submitted after the GPAC meeting. AGA *et al.* also supported revising the initial property damage threshold to reflect inflation at the time of final rule publication. AGA *et al.* stated that the cost of repairing or remediating incident damage in today's environment is far greater than it was in 1984, and that even with the inflation adjustment, more minor events will still be reported

[37] 49 FR 18960.

[38] This analysis is based on the CPI for All Urban Consumers (CPI–U) from the Bureau of Labor Statistics, accessible at *https://data.bls.gov/cgi-bin/cpicalc.pl.*

[39] 85 FR 79130 (Dec. 9, 2020) (updating FRA's monetary threshold for railroad incident reporting requirements by way of annual notices published on FRA's website).

as an incident than would have been in 1984. They asserted that this results in a distorted view of pipeline safety performance, since reportable incidents are often used as a performance metric for the natural gas industry. AGA *et al.* also stated that the increase in the reporting threshold will reduce the number of calls made to the National Response Center (NRC) for minor events that are easily remediated by the operator, and reduce the potential of having to report minor incidents that unnecessarily tie up resources of both the producer and PHMSA. FreedomWorks stated that adjusting the threshold for inflation is simply good housekeeping, adding that it should have been indexed to inflation when the threshold was originally established. This commenter stated their support for including this amendment in the proposed rule while noting that eventually eliminating the property damage criterion entirely would be ideal. Paiute and Southwest also supported the proposed change, noting that it would directly reduce the regulatory burden on them. Southwest further stated that they analyzed the details of the § 191.3 reports their company has made since 2010 where the only reporting criteria met was exceeding the $50,000 estimated property damage threshold and determined that only 9 percent of this subset of reported incidents would have met the revised proposed estimated property damage threshold of $122,000.

TC Energy supported changing the incident definition to adjust the amount of monetary damage to align with inflation, and recommended a monetary damage threshold of $250,000, which they stated would accurately reflect repair costs for minor incidents. They stated that while the proposed threshold of $122,000 may take inflation into account, it will continue to result in several minor incidents being considered reportable due to the cost to respond based on labor, repair materials, and permitting.

AGA *et al.* also supported updating the reporting threshold every 2 years to account for inflation, noting that periodic updates will provide certainty and avoid a repeat of the current situation where the current threshold does not account for over 3 decades of inflation. AGA *et al.* further supported implementing the biennial periodic updates via notice on the PHMSA website, stating that conducting biennial rulemakings to update the threshold seems unnecessarily burdensome for both PHMSA and stakeholders. They asserted that the current NPRM provides adequate notice and opportunity for comment on the proposed method to update the threshold periodically. They recommended that PHMSA revise § 191.3 to clarify in the final rule the agency's intended process for periodically updating the threshold. FreedomWorks recommended that PHMSA mandate a biennial update in the final rule. NPGA agreed with periodic modifications to the threshold, suggesting annual updates by means of a direct final rule published in the **Federal Register**. TC Energy, on the other hand, commented that biennial updates may prove burdensome, but supported incorporating whatever process PHMSA settles on for periodically updating the property damage threshold into the PSR.

NAPSR suggested that PHMSA use the language ''$50,000 or more as measured in 1984 dollars adjusted for inflation,'' which would prevent the need to amend the PSR every year. They further suggested that PHMSA could announce the reporting threshold annually as is done with random drug testing rates, and civil penalties as found in 49 CFR 190, or by simply updating the incident report forms and instructions every year to reflect the recalculated reporting threshold. However, NAPSR also noted that the historical data collected by PHMSA using the prior criteria may result in skewed statistical incident results until several years of collection using the new formula, if adopted, is completed. NAPSR suggested that PHMSA first study the effects of changing the reportable criteria dollar amount and how they plan to reconcile any new data to provide meaningful information to the State programs and to the public. They also suggested that PHMSA consider how such data will relate to any required cost benefit analysis related to future pipeline safety regulations and whether any change to the dollar reporting criteria could affect the ability to promulgate effective regulations.

Two commenters opposed changing the monetary threshold for incident reporting from $50,000 to $122,000. PST commented that PHMSA should be seeking to obtain more information about pipeline failures, not less. They asserted that PHMSA can only make regulatory decisions about design, manufacture or operating conditions that they know cause problems, and if they are told about fewer problems, they will not be able to determine whether they need to regulate certain safety issues. They further stated that if PHMSA is determined to re-define the term ''incident,'' it should undertake a comprehensive look at that definition, and not merely adjust the property damage criteria. They asserted that making incremental, sequential adjustments to the definition will disrupt and frustrate trend analyses, recommending that PHMSA identify, analyze, and consider all potential changes at once. They stated that reducing the number of incidents reported provides PHMSA less safety data, and saves operators very little money, while potentially misleading the public about the improvement in the number of reported incidents that occur in future years. PST further stated that PHMSA and the industry have all committed to pursuing a goal of zero incidents, and that PHMSA should not facilitate that goal by defining reportable incidents away.

Theresa Pugh Consulting also opposed changing the monetary threshold for incident reporting. They stated that since 1984, the United States has become more densely populated such that natural gas pipelines and compressor stations could cause ''partial damage to $50,000 in property that merits reporting to PHMSA.'' While the commenter recognized there is a regulatory cost associated with this reporting, they asserted that it is the cost of doing business in a critical, necessary and dangerous business. The commenter asserted that property damage is still important if it is valued at greater than $50,000, noting that a damaged or lost $50,000 structure or capital equipment can be a major business investment even if it might seem less significant to a multimillion-dollar pipeline project.

One commenter recommended that while PHMSA is addressing the monetary damage limits in the definition of incident in § 191.3, it should also address the issue of how operators determine what constitutes a ''significant event'' under item (iii) of the definition. The commenter stated that the failure of an operator to evaluate their system and define what is significant for their personnel leads to confusion and can cause delayed reporting, or even non-reporting, of incidents.

The GPAC voted 11–2 in favor of PHMSA's proposed amendment to the definition of an incident provided that PHMSA adopted an updated property damage criterion commensurate with the CPI at the time of final rule publication. The GPAC further recommended regular administrative updates using procedures like those proposed by the Federal Railroad

Administration for part 225.[40] Two members voted against the proposed amendments.

3. PHMSA Response

PHMSA agrees with comments supporting the adoption of an up-to-date property damage threshold in the final rule. The most recent complete calendar year is 2019. Therefore, the property damage criterion following the effective date of this final rule is set to $122,000 consistent with CPI inflation between 1984 and 2019.

PHMSA also agrees that it is appropriate to perform updates in the future to account for inflation via a pre-established formula. To this end, PHMSA has incorporated the formula described in the preamble to the NPRM into a new appendix A to part 191. In the future, annual updates to the property damage criterion will be calculated based on this formula and posted to PHMSA's website such that they will become effective July 1 of each year. The revision to the incident definition has no direct safety impact, better reflects the intent of the original property damage criterion, and only impacts reports of releases without significant safety or environmental consequences. Whether a release is classified as an incident has no effect on an operator's regulatory obligation to repair hazardous leaks promptly (§ 192.703) and establish and follow procedures for responding to gas pipeline emergencies (§ 192.615) and investigating failures (§ 192.617). None of the repair criteria in part 192 depend on whether a leak or defect results in a reportable incident.

PHMSA disagrees that changing the property damage criterion adversely affects trend analysis. In fact, a static property damage threshold decreases in real value time. PHMSA already addresses this issue when performing and presenting trend analysis of ''significant'' incidents. PHMSA's analyses of ''serious incidents'' include only incidents that result in reported deaths or injuries and are not affected by inflation because the ''serious'' threshold criteria do not include a property damage criterion. In contrast, PHMSA uses the term ''significant incidents'' to mean those with (1) reported deaths or injuries, or (2) $50,000 or more in total costs, *measured in 1984 dollars.* Additional information on these trend analyses is available on PHMSA's web pages for National Pipeline Performance Measures[41] and Pipeline Incidents, 20 Year Trends.[42] PHMSA currently uses inflation data published by the Bureau of Economic Analysis, the Government Printing Office, and the Energy Information Administration in calculating inflation adjustments for ''significant incidents.'' Following the effective date of the final rule, PHMSA will no longer employ those tools in adjusting the ''significant incident'' property damage threshold for inflation, but will instead use the Bureau of Labor Statistics CPI.

Regarding comments from Theresa Pugh Consulting, PHMSA did not propose to create a new incident definition criterion for releases or pressure drops that disrupt supply to downstream consumers and others indirectly impacted by gas pipeline failures, therefore these suggestions are outside the scope of the NPRM. PHMSA acknowledges that property damage exceeding $50,000 can have a significant effect on third parties affected by the release and notes that it understands that some States have lower incident reporting thresholds to address just that concern.

PHMSA disagrees with comments from TC Energy and FreedomWorks suggesting more radical changes to the property damage criterion. PHMSA does not believe that an arbitrarily higher damage threshold or eliminating the reporting entirely would be appropriate. Even if repair costs may have risen faster than inflation, TC Energy has not provided a convincing rationale for why $250,000 represents current repair costs for incidents across the industry. In addition, while a simple inflation adjustment is consistent with how PHMSA currently uses incident data, a significant change to the incident definition beyond a simple inflation adjustment would affect the ability of PHMSA and other data users to track incident trends as alluded to by other commenters.

PHMSA is deferring for a future rulemaking consideration of the other amendments to the incident reporting criteria at § 191.3 that were suggested by comments received in the rulemaking docket. Further evaluation of those proposals would be helpful.

Corrosion Control

Virtually all hazardous liquid and most natural gas transmission pipelines in service today are made of steel. Metallic pipelines, when not protected, react with the surrounding environment and can deteriorate over time due to corrosion. Under certain conditions, unprotected metal can corrode, causing gas leaks that can threaten public safety. To guard against this, subpart I of part 192 of the PSR requires, with some exceptions, cathodic protection and protective coatings to mitigate corrosion risks on pipelines. Cathodic protection works like a battery, running an electrical current across the buried pipeline using devices called rectifiers. The electrical current prevents the metal surface of the pipe from reacting with its environment. If the current is sufficient, cathodic protection can control corrosion threats.

Subpart I of part 192 establishes requirements for corrosion control and remediation for natural gas pipelines. This subpart also establishes inspection intervals for testing and repairing systems as necessary to bring them into compliance. PHMSA proposed two amendments related to corrosion control: first, to clarify that cathodic protection rectifiers can be inspected remotely and second, to revise the requirements for assessing atmospheric corrosion on distribution service pipelines.

E. External Corrosion Control: Monitoring (Section 192.465)

1. PHMSA's Proposal

In the NPRM, PHMSA proposed to revise § 192.465(b), ''External corrosion control: Monitoring,'' to clarify that operators may monitor rectifier stations remotely. Rectifiers are devices that direct an electrical current on a pipeline to prevent external corrosion. Section 192.465(b) requires inspection of rectifiers on gas pipelines at intervals not exceeding two and a half months, to ensure that they are working correctly. Advances in technology make it possible to monitor the proper operation of these electrical systems remotely, but it is not clear in the regulations if this is permissible. PHMSA proposed to revise § 192.465(b) to clarify that operators may inspect rectifier stations directly onsite or by way of remote monitoring technologies. The NPRM also clarified that, at a minimum, such an inspection consists of recording amperage and voltage measurements. PHMSA also proposed to require operators physically inspect rectifier stations that are being monitored remotely whenever they conduct a cathodic protection test pursuant to § 192.465(a). For pipelines, other than separately protected service lines or separately protected short sections of transmission lines or mains,

[40] As noted earlier, FRA finalized that proposal in December 2020.

[41] *https://www.phmsa.dot.gov/data-and-statistics/pipeline/national-pipeline-performance-measures.*

[42] *https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-20-year-trends.*

§ 192.465(a) requires physical inspection once each calendar year.

2. Summary of Public Comments

Several commenters (including AGA *et al.* and TC Energy) supported PHMSA's proposal allowing remote inspection of impressed current cathodic protection sources. PST stated that they do not oppose allowing the remote inspection of rectifier stations provided the proposed addition of a requirement that remotely inspected rectifier stations be physically inspected once a year is retained. AGA *et al.* and TC Energy recommended that PHMSA clarify that operators must physically inspect remotely inspected rectifiers at the cathodic protection test frequency required in § 192.465(a) and that the rectifier inspection need not necessarily occur at the exact same time as the cathodic protection testing. They indicated that the currently-proposed wording of § 192.465(b)(2) could be interpreted to require a redundant physical inspection of the same rectifier every time each of the pipeline segments influenced by that rectifier is tested, or even multiple times per segment if the testing occurs over multiple days. AGA *et al.* suggested specific revisions to the proposed § 192.465(b)(2).

Four commenters (NPGA, AmeriGas, SPP, and a private citizen) suggested changes to the proposed physical inspection interval. They commented that if rectifier inspection can be done remotely and it is performed at intervals no greater than two and a half months, PHMSA should consider allowing an operator to extend the physical inspection interval for rectifiers on distribution lines beyond once per year, provided the results of remote inspections are properly documented. The commenters claimed that documentation of the results will indicate if, or when, physical inspection of the rectifiers is needed, but did not provide a specific timeline.

One private citizen expressed opposition to the proposed amendment. The commenter requested more frequent inspection of rectifiers, and suggested that the proposed change does not align with industry policies. The commenter noted that corrosion is one of the main causes of pipeline failures and suggested that a physical inspection is already required within the rectifier checks required in § 192.465(b). Based on this interpretation of § 192.465(b), the commenter argued that PHMSA was effectively extending the required interval to perform physical inspections of rectifiers and other devices from six times a calendar year to once per calendar year.

The GPAC voted unanimously in favor of PHMSA's proposal with respect to external corrosion monitoring provided that PHMSA clarify that the physical inspection of a remotely inspected rectifier is expected to occur annually rather than exactly when cathodic protection surveys occur.

3. PHMSA Response

PHMSA has adopted the proposed amendments to § 192.465 with minor revisions to the physical inspection requirements. The amendments clarify that remote inspection is permitted by the PSR. PHMSA's corrosion enforcement guidance contains numerous interpretations clarifying that § 192.465(b) does not specify a particular technology, but rather permits any technology that provides reliable data, including ''electronic data collection and the subsequent broadcast of this data to operators.'' [43] PHMSA expects that the data obtained from remote inspection of rectifiers will not adversely affect the quality and quantity of information available on their function, and does not expect the PSR amendments to § 192.465(b) to have an adverse impact on safety.

PHMSA agrees with comments to specify that the physical inspection should occur annually rather than exactly when a cathodic protection survey is performed under § 192.456(a). This change better reflects PHMSA's intent for operators to perform an annual physical inspection. This change has no impact on the intended frequency of inspections, but provides more flexibility to operators and avoids situations where inspections would have been required more frequently than intended.

PHMSA disagrees with the comment that § 192.465(b) already requires physical inspection during each rectifier inspection and that PHMSA's proposal would lengthen the intervals for physical inspection. While some operators may conduct a physical inspection with each of their rectifier checks, § 192.465(b) currently does not require them to do so.

PHMSA does not adopt a longer physical inspection interval for distribution pipelines as suggested in comments from LPG distribution system operators and suppliers. These comments did not present an alternative timeline that would have been appropriate for distribution operators, and PHMSA believes that operators have ample opportunities to perform an annual physical inspection during other inspection activities.

F. Atmospheric Corrosion: Monitoring (Sections 192.481, 192.491, 192.1007, 192.1015)

1. PHMSA's Proposal

PHMSA proposed to revise § 192.481 to establish a separate atmospheric corrosion inspection interval for gas distribution service pipelines. Currently, all onshore gas pipelines that are exposed to the atmosphere must be inspected for atmospheric corrosion once every 3 years, with intervals not to exceed 39 months. This includes facilities that are installed aboveground, in underground vaults, or inside buildings. PHMSA proposed a maximum inspection interval for service lines of once every 5 calendar years, with intervals not to exceed 63 months, unless atmospheric corrosion was identified on the last inspection. If an operator identifies atmospheric corrosion on a service line during an inspection, then the required interval for the subsequent inspection would remain once every 3 years, with intervals not to exceed 39 months. If no atmospheric corrosion is identified on a subsequent inspection, then operators would be permitted to return to using the 5-year inspection interval. PHMSA also proposed to revise §§ 192.1007(b) and 192.1015(b)(2) to clarify that consideration of corrosion risks under DIMP explicitly includes atmospheric corrosion. PHMSA did not propose any changes to the inspection requirement for other facilities, including distribution mains. PHMSA's proposed change was informed by its understanding that there has not been a history of incidents caused by atmospheric corrosion on distribution service lines since at least 1986 [44] and therefore does not anticipate a decrease in safety from these PSR revisions.

2. Summary of Public Comments

Several commenters (including Oleksa and Associates, FreedomWorks, and AGA *et al.*) expressed support for establishing a separate atmospheric corrosion inspection interval for gas distribution service pipelines. FreedomWorks stated that the changes would reduce the costs for both

[43] See, *e.g.*, PHMSA Pipeline Enforcement Guidance: Part 192 Corrosion Enforcement Guidance (2015), available at *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/Corrosion_Enforcement_Guidance_Part192_12_7_2015.pdf* (citing PHMSA Interpretation #PI–ZZ–080 (Aug. 19, 1991)).

[44] 1986 is the earliest year available in the ''Pipeline Incident Flagged Files'' dataset. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files.*

operators and inspectors. AGA *et al.* supported revising § 192.481 to align the inspections intervals for atmospheric corrosion with those of leak surveys required by § 192.723. AGA *et al.* asserted that the NPRM's proposed PSR revisions would reduce regulatory burdens while enhancing pipeline safety in that the resources saved from such alignment could be reallocated to other pipeline safety activities and asset improvement projects.

Some commenters (including SPP, NPGA, and AmeriGas) supported the extension of the inspection interval to 5 years for service lines, but recommended that if documented action were taken to remediate the coating as specified in § 192.479, then the inspection interval should remain at 5 years. The commenters stated that there is not a need to drop down to 3 years if remediation occurs.

AGA *et al.* and GPTC agreed that the existing 3-year interval when corrosion is identified is not necessary to manage atmospheric corrosion risks if the service line is replaced or remediated, especially considering existing DIMP requirements, and the proposed requirement to consider atmospheric corrosion risks under DIMP included in the NPRM. They agreed with PHMSA's assessment that there is expectation for operators of service lines in high-corrosion environments to consider atmospheric corrosion in their evaluation of risks under DIMP and conduct atmospheric corrosion inspections more frequently than the minimum requirements in § 192.481. AGA *et al.,* therefore, recommended a prescriptive remediation requirement in lieu of a shortened inspection cycle. They stated that by remediating through recoating or replacement, operators can continue to keep all service pipelines on a 5-year inspection cycle. They provided specific regulatory text revisions in their comment. AGA *et al.* also requested that PHMSA remove the word ''evaluate'' from § 192.481(a). They noted that PHMSA did not provide justification for adding the requirement to evaluate under § 192.481(a). INGAA, AGA, APGA, API, and GPA Midstream submitted supplemental comments after the GPAC meeting arguing that the 3-year inspection interval when corrosion has been identified would negate any cost savings from the proposed revisions to § 192.481.

Similarly, NAPSR commented that if atmospheric corrosion is found that corrosion should be remediated rather than be subject to a shorter inspection interval. NAPSR argued this would be more reliable from a safety perspective than establishing a shorter inspection interval. Alternatively, NAPSR recommended that PHMSA consider revising both §§ 192.481 and 192.723 to require a shorter, perhaps 3- or 4-year, residential leak survey requirement and require that operators complete their atmospheric corrosion survey at the same interval. NAPSR argued this would provide for greater safety regarding leak surveys, while making it more practical to combine compliance intervals for two operation and maintenance categories. NAPSR further commented that any change to the atmospheric corrosion control inspection interval should be accompanied by a change to the record keeping requirements in § 192.491. NAPSR recommended that operators be required to retain records for the previous two inspection cycles.

A2LA recommended that PHMSA implement a risk-based approach to determine permissible inspection intervals rather than the 3-year or 5-year intervals described in the NPRM. A2LA stated the risk-based approach can then account for considerations such as the age of the pipeline, climate, geologic conditions, use, and maintenance history. They agreed with the proposed rulemaking that the maximum inspection interval for service lines should be 5 calendar years, with intervals not to exceed 63 months.

Two gas distribution operators and an industry organization commented that it is unclear whether, if corrosion was identified, a 3-year inspection interval would be required for the entirety of the distribution system or just at the location or address where the corrosion exists. They recommended that PHMSA consider clarifying that the 3-year inspection interval applies to ''only such areas as corrosion was identified.''

PST commented that they are unable to support changes in monitoring frequency because corrosion continues to cause many incidents. They commented that corrosion-related incidents indicate that more prescriptive corrosion monitoring regulations might be warranted. However, they noted that they do not strongly oppose this change, as PHMSA indicates it has no recent records of incidents caused by atmospheric corrosion on distribution service lines.

The GPAC voted twice on this amendment. First, the GPAC voted 7–5 in favor of the proposed rule with respect to atmospheric corrosion, provided that PHMSA amend § 192.491(c) to clarify that an operator must retain records of the last two atmospheric corrosion inspections to use the 5-year inspection interval. This vote recommended retaining the proposed requirement to inspect lines where corrosion was identified on the last inspection within 3-years, and did not incorporate the remediation alternative to a 3-year inspection that was suggested by some commenters.

Second, the GPAC voted 10–2 in favor of the proposed rule with respect to atmospheric corrosion if PHMSA adopted a 5-year cycle rather than a 3-year cycle when atmospheric corrosion is found, provided that the operator has evaluated and remediated the facility and there is no evidence of systemic atmospheric corrosion due to the environment or similar factors.

3. PHMSA Response

After considering the public comments and the GPAC recommendations, the final rule adopts the amendment with respect to atmospheric corrosion inspection of service lines as proposed with minor clarification to recordkeeping requirements in § 192.491(c). Alignment of atmospheric corrosion inspection intervals with those for leakage surveys in § 192.723 will allow greater scheduling flexibility for operators and decreased costs arising from less frequent atmospheric inspections. As stated in the NPRM, PHSMA is unaware of any pipeline incidents arising from atmospheric corrosion on a service line. In addition, PHMSA has approved State waivers in the past that have allowed certain operators to perform both atmospheric corrosion and leakage surveys on a 4-year interval outside of business districts and subject to certain conditions. The most recent of these was for North Western Energy in South Dakota, issued March 2, 2019.[45] PHMSA has not observed an increase in leaks or incidents from this and other State waivers. For these reasons, PHMSA finds that a longer atmospheric corrosion inspection interval is supported in areas with low observed atmospheric corrosion risk.

The final rule applies the new 5-year inspection interval to distribution service lines. Although PHMSA acknowledges that operators have reported atmospheric corrosion incidents on distribution mains, PHMSA understands the design and operational characteristics of service lines make them less susceptible to atmospheric corrosion induced failure. Compared to distribution mains, service lines tend to have smaller diameters,

[45] Additional information on these historical examples is available in the rulemaking docket and the docket for the South Dakota State waiver (PHMSA–2019–0052).

have lower flow rates, and are constructed with thicker walls relative to the outside diameter of the pipeline. They can therefore endure more atmospheric corrosion induced metal loss before operating stresses would compromise pipeline integrity. In addition, aboveground distribution facilities other than service lines (*i.e.* mains) must be inspected more frequently under part 192, providing ample opportunity for operators to note and correct any corrosion issues.

PHMSA recognizes that not all environments face the same atmospheric corrosion risks. However, based on inspection results and field experience, PHMSA determined that establishing a maximum inspection interval is necessary to ensure that distribution facilities are adequately inspected for atmospheric corrosion sufficiently frequently so that it can be remediated before it leads to a failure. An open-ended reference to DIMP, as suggested in the Associations' comment on the DOT Notification of Regulatory Reform, would not provide this safeguard. The proposed maximum interval of 5 years was supported in public comments and will allow operators of gas distribution pipelines with low atmospheric corrosion risks to realize cost savings from less-frequent inspections and the ability to schedule corrosion inspections and leakage surveys under § 192.723(b)(2) concurrently. PHMSA was not persuaded that there is significant benefit to allowing atmospheric corrosion inspection intervals longer than the maximum leakage survey interval as described by some commenters. Inspecting the aboveground portion of a service line is not a significant additional burden when operators are already walking the service line to perform leakage surveys.

The proposed revisions to §§ 192.1007(b) and 192.1015(b)(2) to evaluate atmospheric corrosion risks under DIMP and the shorter inspection interval for pipelines with observed corrosion will also ensure that operators of service pipelines with atmospheric corrosion threats take appropriate action to maintain the integrity of those pipelines.

Those revisions clarify that consideration of corrosion under DIMP must include consideration of atmospheric corrosion risks. When evaluating atmospheric corrosion risks under DIMP, PHMSA expects operators to evaluate environmental risk factors and the operating history of the service lines. Environmental risk factors for atmospheric corrosion include proximity to coasts, atmospheric moisture, salinity, and corrosive pollution. Relevant operational risks include a history of leaks, incidents, and evidence of atmospheric corrosion on previous inspections. PHMSA expects operators of distribution lines with higher risks due to atmospheric corrosion threats to take mitigative action, such as more frequent inspection or maintenance activities, as part of their DIMPs and accurately and completely document such actions.

The final rule does not adopt proposals (by commenters and GPAC) for remediation as an alternative to the NPRM's approach of shorter inspection intervals following observation of atmospheric corrosion. While commenters suggested a ''prescriptive'' remediation requirement, the regulatory language suggested in comments from the Associations neither defines what constitutes an adequate repair of atmospheric corrosion (other than replacement), nor how their proposal differs from existing part 192 requirements for remediation and repair of atmospheric corrosion and other conditions that could reduce the pipeline's integrity. Based on the GPAC discussion, remediation as discussed by commenters consists of removing corrosion with a wire brush and repainting the facility pursuant to the existing § 192.479 requirements. These actions are already required by existing § 192.481, through reference to § 192.479, which requires an operator to clean and suitably coat pipelines exposed to the atmosphere, and § 192.703 requires operators to replace, repair, or remove pipeline segments that become unsafe and promptly repair all hazardous leaks. In addition, finding atmospheric corrosion is an indication that a corrosive environment may exist. Inspection of such service lines within 3 years protects against this risk. Any remediation alternative requires careful consideration of what constitutes adequate remediation because corrosion has already been identified on the pipeline.

PHMSA also declines to NAPSR's alternative approach of aligning atmospheric corrosion inspection and leaky survey frequencies by revising § 192.723 to require more frequent leak surveys. PHMSA is unaware of record evidence supporting a need for shortened leak survey intervals, even as PHMSA finds that the absence of incidents resulting from atmospheric corrosion support extending the inspection interval as provided by this final rule. In addition, more frequent leak inspection surveys under § 192.723 will likely entail significant operator costs without record evidence of a corresponding safety benefit.

PHMSA is not persuaded by arguments raised by GPAC members and comments submitted after the GPAC meeting that reverting to a 3-year inspection interval for a distribution service line after atmospheric corrosion has been observed makes the amendment technically impracticable or economically infeasible. A 3-year inspection interval is the current requirement that has been in place for decades. Based on cost estimates provided by industry comments, PHMSA determined in the RIA that significant cost savings for the NPRM's proposed revisions to atmospheric corrosion monitoring requirements stem from reduced inspection frequency in the absence of observed atmospheric corrosion. If, however, the operator observes atmospheric corrosion and remediates it as required in part 192, then an operator should rarely observe atmospheric corrosion during the 3-year inspection following remediation, after which they may return to a 5-year inspection interval and continue to enjoy cost savings into the future. An operator can easily keep atmospheric corrosion and leakage surveys in sync by performing the next leakage survey within 3 years and then continuing every 5 years on subsequent inspections provided no corrosion is identified in the future. If the operator is unable to use the 5-year inspection interval effectively because they repeatedly observe atmospheric corrosion, then the rule is working as intended to protect the public in areas with high rates of atmospheric corrosion.

Finally, consistent with the recommendations of the GPAC and comments received in the rulemaking docket, the final rule revises the corrosion control recordkeeping requirements in § 192.491(c) to clarify that an operator must retain records of the two most recent atmospheric corrosion inspections in order to use the 5-year inspection interval for facility distribution service line. This change ensures that operators can provide adequate documentation that corrosion was not identified on a service line that is being inspected on a 5-year interval.

ASTM and ASME Standards Incorporated by Reference

G. Plastic Pipe (Sections 192.7, 192.121, 192.281, 192.285, Appendix B to Part 192)

1. PHMSA's Proposal

The NPRM proposed to update §§ 192.7, 192.121 and appendix B to part 192 to incorporate by reference the

2018a edition of the ASTM International (ASTM, formerly the American Society for Testing and Materials) document, ''Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings'' (ASTM D2513–18a).[46] ASTM D2513 specifies the design requirements of Polyethylene (PE) pipe and fittings. These improvements include more specific testing requirements for measuring resistance to ultraviolet exposure and clarifying the applicability of the document to all PE fuel gas piping. Consistent with the updated ASTM standard, PHMSA also proposed to raise the diameter limit for using a design factor of 0.4 on PE pipe from 12 inches to 24 inches and add corresponding entries for those sizes to the PE minimum wall thickness table at § 192.121(c)(2)(iv). PPI, representing manufacturers of plastic pipe and components, and a citizen commenter submitted comments in response to the DOT Notification of Regulatory Review addressing this issue. PHMSA reviewed ASTM D2513–18a and determined that PE pipe with diameters up to 24 inches that are manufactured in accordance with the standard and the design and construction requirements in part 192 are acceptable for use in gas pipeline systems. PHMSA also determined that the other safety improvements since the 2012ae1 edition merit incorporation by reference in the PSR as their incorporation would not have an adverse impact on safety, while improving regulatory clarity and alignment with consensus industry practices.

Currently, PHMSA incorporates by reference ASTM D2513–12ae1 into item I, appendix B to part 192. While Table 2 (Outside Diameters and Tolerances for Plastic Pipe) of ASTM D2513–12ae1 includes outside diameter specifications for pipe sizes up to 24-inch nominal diameter, Table 4 (Wall Thicknesses and Tolerances for Plastic Pipe) only includes wall thickness specifications for pipe sizes up to 12-inch nominal diameter. Because ASTM D2513 is the listed specification for PE plastic pipe in appendix B to part 192, and § 192.121(c)(2)(iv) mirrored the published wall thicknesses and tolerances in Table 4 of ASTM D2513–12ae, part 192 does not currently allow use of a 0.4 design factor for PE pipe diameters above 12 inches. Now that the ASTM D2513–18a includes in its Table 4 wall thicknesses for diameters through 24 inches, the corresponding table in § 192.121(c)(2)(iv) can be updated as well.

In the NPRM, PHMSA also proposed to modify requirements for joining procedures in §§ 192.281 and 192.285 to allow operators additional flexibility when developing such procedures and to improve safety. Specifically, PHMSA proposed to incorporate by reference the 2019 edition of ASTM F2620, ''Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings'' and revise §§ 192.281 and 192.285 to clarify that procedures that are demonstrated to provide an equivalent or superior level of safety as ASTM F2620 are acceptable. This amendment addresses concerns raised by a petition for reconsideration submitted by AGA on August 23, 2019[47] in response to the final rule entitled ''Pipeline Safety: Plastic Pipe Rule'' issued on November 20, 2018.[48]

In the Plastic Pipe Rule, PHMSA amended §§ 192.281 and 192.285 to require that PE heat-fusion joining procedures meet the requirements of the 2012 edition of ASTM F2620. Heat fusion is a common method for joining plastic pipe and components. In heat fusion, a worker prepares the surfaces of the pipe or fittings being joined, heats the surfaces using a heating element, and then presses the pipe or fittings together with sufficient force for the molten material to mix and fuse as it cools. ASTM F2620 describes procedures for making socket fusion, butt fusion, and saddle fusion joints. The document contains requirements for the selection, preparation, and maintenance of joining equipment; preparing surfaces for joining; specified heating temperatures and times; joining forces; and cooling procedures. The standard also includes considerations for joining in cold weather and criteria for evaluating the quality of fusion joints.

AGA raised concerns that §§ 192.281 and 192.285 could be interpreted to require operators to requalify safe procedures that had been qualified in the past in accordance with § 192.283. AGA commented that many operators use heat fusion procedures published by PPI, such as PPI TR–33 and PPI TR–41. While PHMSA noted in the preamble of the Plastic Pipe Rule that PHMSA would find a joining method acceptable if ''an operator can demonstrate the differences are sound and provide equivalent or better safety compared to ASTM F2620,'' AGA raised concerns that the regulatory text itself does not necessarily provide this flexibility, and suggested PHMSA explicitly allow the use of other qualified procedures, such as PPI TR–33 and PPI TR–41.

In the NPRM, PHMSA proposed to revise §§ 192.281 and 192.285 to achieve the flexibility sought in the Plastic Pipe Rule. Specifically, PHMSA proposed to revise § 192.281(c) to allow an alternative written procedure to ASTM F2620, provided that the operator can demonstrate that it provides an equivalent or superior level of safety and has been proven by test or experience to produce strong, gastight joints. In other words, the procedure produces joints that do not allow gas to leak, are at least as strong as the pipe being joined, are designed to handle the expected environment and the internal and external loads, and have been validated by formal testing in accordance with § 192.283 and applicable standards incorporated by reference or through several years of operational experience without leaks or failures.

As described in the preamble to the Plastic Pipe Rule, for operators to demonstrate compliance, PHMSA expects operators to document the differences from ASTM F2620 and demonstrate how the alternate procedures provide an equivalent or superior level of safety. Similarly, PHMSA proposed to revise § 192.285(b)(2)(i) to allow other written procedures that have been proven by test or experience to produce strong, gastight joints. If the operator's procedures are found to be lacking in any way—such as changes to surface preparation, heating temperatures, fusion pressures, cooling times that lack a technical justification demonstrating an equivalent or superior level of safety—they would be unacceptable and would not comply with the PSR.

PHMSA also proposed to incorporate by reference the 2019 edition of ASTM F2620. The updated edition of the standard clarifies the relationship between ASTM F2620 and the certain PPI documents referenced in AGA's petition within a new Note 1 in section 1.2. That Note identifies parameters and procedures in F2620 that were developed and validated using PPI TR–33 (butt fusion) PPI TR–41 (saddle fusion), thereby facilitating operators' ability to referencing those PPI documents in developing their technical justification for use of an alternative procedures under § 192.285(b)(2)(i). In addition, the 2019 edition of ASTM F2620 includes several incremental improvements on the 2012 edition to safety and editorial clarity. These improvements include a new section 6.4 that requires additional precautions

[46] ASTM International, ASTM D2513–18a—''Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings'' (Aug. 1, 2018).

[47] Docket Number PHMSA–2019–0200. *https://www.regulations.gov/docket?D=PHMSA-2019-0200.*

[48] 83 FR 58694.

during pipe cutting to prevent the introduction of contaminants that can weaken the joint and a new section X4.2 that references the required test method for qualifying plastic pipe joiners in § 192.285. Further, the 2019 edition revises the recommended precautions for preventing or removing contamination during pipe cutting in section X1.7.1 to clarify that any soap is a contaminant and that contamination may be introduced during cutting, and to require cleaning of the outer and inner surface of the pipe in addition to the end. These changes are expected to reduce potential issues caused by inadequate surface preparation, which has been a factor in past incidents.[49]

PHMSA also proposed to clarify § 192.285 in response to questions PHMSA has received following publication of the Plastic Pipe Rule. First, PHMSA proposed to remove references to testing in relation to ASTM F2620 to clarify that only visual inspection in accordance with that standard is required. Several stakeholders asked what specific testing is required in ASTM F2620. While ASTM F2620 describes testing in a non-mandatory appendix of the standard, it does not require specific testing. Clarifying that operators must visually inspect specimen joints in accordance with ASTM F2620 avoids confusion about whether non-mandatory testing described in ASTM F2620 is required by § 192.285(b)(2)(i). PHMSA also proposed to clarify that testing in accordance with § 192.283(a) is still required for PE heat fusion joints. The current text could be read to require only visual inspection in accordance with ASTM F2620 for PE heat fusion joints. The changes in this rule clarify PHMSA's intent to require that such joints be tested in accordance with § 192.283(a) and visually inspected in accordance with ASTM F2620. Additional testing in accordance with the appendix of ASTM F2620 is optional.

In addition to the matters raised above, PHMSA proposed correcting amendments to address the following:

Design Pressure for Plastic Pipe

In § 192.121(a), PHMSA proposed the words ''design formula'' be replaced with the words ''design pressure,'' which is more accurate.

Minimum Wall Thickness for 1″ CTS Pipe

In the minimum wall thickness tables for PE (§ 192.121(c)(2)(iv)), polyamide 11 (PA–11) (§ 192.121(d)(2)(iv)), and polyamide 12 (PA–12) (§ 192.121(e)(4)) pipe, PHMSA proposed that the minimum wall thickness for standard dimension ratio (SDR) 11, 1″ copper tubing size (CTS) pipe is corrected to be 0.101 inches rather than 0.119 inches. The former, 0.101 inches, most closely corresponds to SDR 11, 1″ CTS pipe in the standards incorporated by reference for the design of PE (ASTM D2513), PA–11 (ASTM F2945),[50] and PA–12 (ASTM F2785)[51] plastic pipe and fittings.

Qualifying Joining Procedures

In § 192.283(a)(3), ''no more than 25% elongation'' is corrected to read ''no less than 25% elongation.'' PHMSA proposed to clarify that the test required by this section is a tensile test. Tensile testing is a measure of a material's resistance to pulling forces. The revisions to § 192.283(a)(3) made in the Plastic Pipe Rule inadvertently removed the word ''tensile,'' though tensile strength was still alluded to implicitly because elongation is a measure of tensile strength. Reinserting the word tensile clarifies this relationship.

Dates

In § 192.121(c)(2) and (e), PHMSA proposed to clarify that PE pipe and PA–12 pipe respectively produced on or after January 22, 2019 may use a DF of 0.40 rather than 0.32, subject to applicable restrictions in those paragraphs.

Corrections to 192.7

PHMSA proposed editorial amendments to § 192.7(a) to meet incorporation by reference requirements of the Office of the Federal Register and a revision to update the address for API.

2. Summary of Public Comments

ASTM D2513 and PE Pipe Diameter

Several commenters provided their support, with no additional comments, for the proposed amendments in the NPRM.

AIPRO submitted comments supporting the incorporation by reference of the 2018a edition of ASTM D2513 and conforming revisions to § 192.121. Similarly, PPI stated their support to increase the allowable dimensions for PE pipe using a 0.40 design factor up through 24 inches along with the corresponding minimum wall thicknesses in Table 1 to paragraph § 192.121(c)(2)(iv). PPI stated that the revisions are consistent with dimensions provided in ASTM D2513–18a and enables the increased use of larger diameter PE in gas distribution, transmission, and gathering systems.

PPI provided suggested regulatory text revisions for § 192.121(a) to permit an operator to allow an operator to operate a plastic pipe at a temperature up to 180 °F, provided that the hydrostatic design basis (HDB) is established at that temperature. PPI noted that a survey of AGA members indicated that local distribution companies desire to use plastic pipe at higher operating temperatures providing them with more application options, and that use of these higher performance plastic materials results in increased long-term performance of the piping system and a safer gas system.

GPA Midstream supported incorporating by reference updated editions of standards and believes that the latest editions should be adopted wherever possible. GPA Midstream stated that relying on obsolete or outdated editions of IBR standards creates unnecessary compliance burdens, discourages innovation, and adversely affects the standards development process. GPA Midstream noted that a significant number of the IBR standards have undergone multiple revisions without being updated to a newer or more recent edition. GPA Midstream requested that PHMSA place a renewed emphasis on the timeliness of the incorporation by reference process, particularly in cases where a prior edition of a standard is already incorporated by reference. In such cases, PHMSA should commit to adopting the latest edition of the standard or providing an explanation for not doing so within 1 year of publication.

ASTM F2620 and Joining Requirements

AGA *et al.* supported the changes proposed to §§ 192.281 and 192.285. They commented that the proposed revisions in the NPRM aligned with AGA's petition for reconsideration of the Plastic Pipe Rule, and allow operators to use alternate procedures to join PE which are equivalent or more stringent than the heat fusion procedure detailed in the 2012 edition of ASTM F2620.

PPI supported PHMSA's proposed revision to §§ 192.281(c) and 192.285 providing for alternative written heat fusion procedures that provide an equivalent or superior level of safety.

[49] National Transportation Safety Board, ''Safety Through Reliable Fusion Joints,'' SA–047 (June 2015), *https://www.ntsb.gov/safety/safety-alerts/Documents/SA_047.pdf.*

[50] ASTM F2945–12a ''Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings'' (Nov. 27, 2012).

[51] ASTM F2785–12, ''Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings'' (Aug. 1, 2012).

PPI also suggested incorporating PPI–TR–33, ''Generic Butt Fusion Joining Procedure for Field Joining Polyethylene Pipe'' and TR–41, ''Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping'' into § 192.281(c) in addition to ASTM F2620. PPI explained that these additions would help clarify the language and account for proven procedures that have been successfully used in industry for many years. A2LA suggested that PHMSA also incorporate by reference ISO/IEC 17025, ''General Requirements for the Competence of Testing and Calibration Laboratories'' and require alternative written procedures be validated by laboratories certified in accordance with that document. A2LA commented that ISO/IEC 17025 recommends that a testing laboratory uses consensus methods and has procedures for the selection of methods, and verify that a testing laboratory can properly perform methods by ensuring that it can achieve the required performance and maintain records of the verification. Regarding PHMSA expecting operators to document the differences from ASTM F2620 and demonstrate how the alternate procedures provide an equivalent or superior level of safety, A2LA recommended that the organizations conducting the inspections and testing be accredited, in accordance with the relevant ISO/IEC standards include requirements for impartiality.

Southwest Gas Corporation (Southwest) raised concerns with the addition of the language ''or superior'' in the proposed language of both §§ 192.281 and 192.285. Southwest believes that this language ''or superior'' implies an increased performance standard not defined in either ASTM F2620 or part 192. Southwest requested that PHMSA consider removing the language ''or superior'' from the proposed revisions to both § 192.281(c) and § 192.285(b)(2)(i) and provided its preferred regulatory text.

1-Inch CTS Pipe

The Associations and NAPSR commented that operators commonly use 1-inch CTS pipe with a wall thickness of 0.099 inches, rather than 0.101 inches in the proposed rule. Both wall thickness specifications are listed as options in Table 3 of ASTM D2513. NAPSR requested clarification of whether operators are required to use a design factor of 0.32 for PE pipe with a minimum wall thickness of 0.099-inch, and if thicker pipe is required to use a 0.40 design factor. The Associations raised concerns about the impact to operators and manufacturers who have an inventory of 0.099-inch wall thickness PE pipe and suggested that PHMSA correct the proposed amendments to the minimum wall thickness table at § 192.121(c)(2)(iv) to reference 0.099-inch thick, 1-inch CTS pipe that is commonly in use.

Qualifying Joining Procedures

PPI supported correcting § 192.283(a)(3), and allowing visual inspection in accordance with established written procedures in § 192.285(b)(2)(i).

GPAC Recommendation

The GPAC voted unanimously in favor of PHMSA's proposed amendment with respect to plastic pipe requirements, provided PHMSA correct the minimum wall thickness tables to specify a 0.099-inch wall thickness for 1-inch CTS plastic pipe as recommended in the written comments from the Associations and NAPSR.

3. PHMSA Response

Based on the comments, the final rule adopts the plastic pipe amendments as proposed except for a change to the minimum wall thickness required to use plastic pipe with a size of 1-inch CTS with a design factor of 0.40 rather than 0.32. The final rule incorporates the 0.099-inch minimum wall thickness for 1-inch CTS plastic pipe.

PHMSA expects that the incorporation of updated industry standards pertaining to plastic pipe design will not adversely affect safety. The updated standards incorporated by reference in this final rule reflect the benefit of testing, lessons learned, and operational best practices from the increasingly widespread use of plastic pipe in gas transmission, distribution and gathering applications. Significantly, those updated industry standards reflect a greater comfort within industry regarding the safety of the use in those applications of larger-diameter plastic piping when subject to rigorous design standards. Based on its review of those standards and the administrative record in this rulemaking, PHMSA is similarly satisfied that their incorporation within the PSR will not have a detrimental impact on safety. PHMSA has provided a discussion of the changes in the updated editions of ASTM D2513 and ASTM F2620 in the summary of the proposed changes in section III.G.1 above.

ASTM D2513 and PE Pipe Diameter

The final rule incorporates by reference the 2018a edition of ASTM D2513 and allows the use of a 0.40 design factor for PE pipe produced on or after the effective date of the rule with a maximum diameter of 24 inches as proposed in the NPRM. PHMSA proposed no changes to the design pressure formula for PE pipe at § 192.121(c)(2), and therefore declines to adopt the design factor change for PE piping suggested by PPI without the benefit of further technical evaluation and public comment. Similarly, PHMSA may consider allowing an operator to more directly establish a HDB rating at 180 °F within the design pressure formula at § 192.121(a) in a future rulemaking after further review of the safety effects of such a change. PHMSA notes that § 192.121(a) allows an operator to interpolate the design pressure down from 180 °F, meaning they could use a pipe with an HDB rating at 180 °F but have to use a formula to determine the design pressure at a lower temperature listed in § 192.121(a). PHMSA cautions users that not all PE compounds are rated at 180 °F.

Regarding the GPA Midstream comment concerning other documents that are currently incorporated into part 192, PHMSA periodically issues rules updating the standards that are incorporated by reference, provided the 2018 edition of ASTM D2513 has been evaluated and its incorporation determined consistent with PHMSA's safety mission. More recent versions of this and other standards incorporated by reference, including those related to plastic pipe and components, that were not included in the NPRM may be considered for updates in other rulemaking proceedings.

ASTM F2620 and Joining Requirements

The final rule also adopts the clarifications to joining requirements as proposed with minor editorial revisions. PHMSA did not propose in the NPRM to incorporate by reference PPI TR–33, PPI TR–41, or ISO/IEC 17025, and therefore declines to incorporate them by reference without the benefit of additional public comment and technical evaluation. However, PHMSA understands that many of the procedures in TR–33 and TR–41 are similar or identical to the procedures specified in the 2019 edition of ASTM F2620. There are, however, still some differences such as heating temperatures. If an operator can demonstrate that their alternative procedure based on those documents provides an equivalent or superior level of safety compared with ASTM F2620, it would be acceptable under the amendments adopted in this final rule.

PHMSA disagrees with comments that including the phrase ''or superior'' imposes new requirements or adds uncertainty to the changes in §§ 192.281 and 192.285. An operator need only demonstrate that their alternative procedure provides an equivalent level of safety; the addition of the term ''or superior'' exists to ensure that a procedure with requirements that may be more conservative than ASTM F2620 is also acceptable. PHMSA has revised the regulatory language at § 192.281 proposed in the NPRM to clarify that the operator need only demonstrate that the alternative procedure provides an equivalent or superior level of safety rather than demonstrate the alternative procedure is itself superior.

1-Inch CTS Pipe

PHMSA agrees with commenters that 0.099 is an acceptable minimum wall thickness specification. While 0.101 inches more closely corresponds to SDR 11, both 0.099-inch and 0.101-inch wall thickness for 1-inch CTS pipe are technically SDR 11 specifications. In addition, the two specifications are within allowable tolerances of each other in the ASTM codes. Therefore, PHMSA does not have a safety concern with using a 0.40 design factor with 0.099-inch wall thickness for 1-inch CTS plastic pipe and recognizes that it is in common use.

H. Test Requirements for Pressure Vessels (Section 192.153)

1. PHMSA's Proposal

Section 192.153 defines design requirements for prefabricated units and pressure vessels (hereafter referred to as pressure vessels) fabricated by welding. In particular, § 192.153(a) requires that operators establish the design pressure of components fabricated by welding whose strength cannot be determined to establish the design pressure of those components in accordance with section VIII, division 1 of the 2007 edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC) which is incorporated by reference in § 192.7.[52] Section 192.153(b) requires operators to design, construct, and test prefabricated units that use plate and longitudinal seams in accordance with either ASME BPVC section I, section VIII, division 1, or section VIII, division 2. In addition, § 192.505(b) requires operators to pressure test compressor station, regulator station, and measuring stations to Class 3 location test requirements; for pipelines installed after November 11, 1970, this represents a required test factor of at least 1.5 times the maximum allowable operating pressure (MAOP).[53]

On March 11, 2015, PHMSA published a final rule titled, ''Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations.'' [54] The final rule created a new § 192.153(e), which clarified that pressure vessels subject to § 192.505(b) must be pressure tested to at least 1.5 times the MAOP of the pipeline. INGAA subsequently submitted a petition for reconsideration of the Miscellaneous Rule concerning the revision to § 192.153.[55] The petitioner argued that PHMSA lacked technical justification for a 1.5 times MAOP test factor versus the 1.3 times the Maximum Allowable Working Pressure (MAWP) [56] test factor permitted in the ASME BPVC since the 2001 edition and all subsequent editions of the standard. PHMSA had incorporated by reference the 2001 edition of the ASME BPVC into part 192 effective July 14, 2004, and the divergence between the required test factor in § 192.505(b) and section VIII, division 1 of ASME BPVC persisted until the Miscellaneous Rule became effective in 2015.[57]

PHMSA, meanwhile, had commissioned a report by the Oak Ridge National Laboratory (ORNL) on the safety equivalence between the 1992 edition and the 2015 edition of the ASME BPVC. PHMSA understands that most pressure vessels in pipeline service are designed to ASME section VIII, division 1. For hydrostatic pressure tests, the 1992 edition of section VIII division 1 of the ASME BPVC provides for a hydrostatic pressure test factor of 1.5 times MAWP, while the 2001 and all subsequent editions provide for a hydrostatic pressure test factor of 1.3 times MAWP. The ORNL report found that these different editions of ASME BPVC section VIII, division 1 maintain safety through the design and fabrication of pressure vessels and hydrostatic pressure test, notwithstanding the difference in their hydrostatic pressure test factors of 1.3 and 1.5. A copy of this report is available in the docket.

In the NPRM, PHMSA proposed to revise the test requirements for the pressure vessels described in § 192.153. First, PHMSA proposed to revise § 192.153(e) to require a pressure test factor of at least 1.3 times the MAOP for all pressure vessels installed since July 14, 2004, provided the component has been tested in accordance with the ASME BPVC, as required by existing § 192.153(b). Consistent with this change and the requirements in the ASME BPVC, PHMSA also proposed to exempt vessels installed after July 14, 2004 from the strength testing requirement at §§ 192.505(b) and 192.619(a)(2), which require a test factor of 1.5 times the MAOP. The test requirements for any pressure vessel with an MAOP established under the alternative MAOP requirements at § 192.620 would remain unchanged.

Second, PHMSA proposed a new § 192.153(e)(2) that would exempt pressure vessels installed after July 14, 2004 but before the effective date of the final rule from testing duration requirements at §§ 192.505(c), (d) and 192.507. In contrast, pressure vessels installed on or after the effective date of the final rule would be subject to the long-standing pressure test duration requirements in subpart J.

Third, PHMSA proposed § 192.153(e)(3)(ii) to accept, subject to certain conditions, a pre-installation pressure test by the component manufacturer for pressure vessels installed after the effective date of the final rule but which have not previously been used in service. PHMSA proposed to accept those manufacturer pressure tests for the purposes of meeting the pressure testing and MAOP requirements in part 192 provided the operator conducts and documents an inspection certifying that the pressure vessel has not been damaged during transport and installation into the pipeline. If the inspection reveals that the pressure vessel has been damaged, the component would have to be remediated consistent with the ASME BPVC and part 192. A pressure vessel used prior to installation on a pipeline facility would have to be pressure tested again, consistent with the existing requirement at § 192.503(a).

2. Summary of Public Comments

AGA *et al.* generally supported the PSR amendments proposed in the NPRM but suggested substantive revisions to the requirements for accepting a manufacturer's test of a pressure vessel. AGA *et al.* emphasized that the NPRM's integration of ASME

[52] ASME Boiler & Pressure Vessel Code, 2007 edition (July 1, 2007).

[53] Section 192.619(a)(2) requires a test pressure of at least 1.5 times the MAOP in a Class 3 or Class 4 location for pipelines installed after November 11, 1970.

[54] 80 FR 12762 (Miscellaneous Rule).

[55] Docket No. PHMSA–2018–0046–0055.

[56] MAWP is the design pressure in the ASME BPVC. The test factors in the ASME BPVC refer to the MAWP and are used to substantiate the design pressure of the vessel. Because the design pressure of a pressure vessel (the MAWP) must be equal to or greater than the MAOP of the pipeline, the PSR uses the more demanding MAOP metric.

[57] PHMSA, ''Pipeline Safety: Periodic Updates to Pipeline Safety Regulations,'' 80 FR 12762 (June 14, 2004).

BPVC requirements within its proposed PSR revisions leverages an internationally recognized standard of safety applied by several Federal regulators in their oversight activities. AGA *et al.* agreed with the NPRM's approach of allowing operators to rely on a manufacturer's pressure test accompanied by a visual inspection for newly-manufactured vessels, but requested PHMSA extend this authorization to relocations of existing components as well.

AGA *et al.* noted that retesting ASME pressure vessels is not required by the ASME BPVC—but if an operator voluntarily undertook retesting, the ASME BPVC would require oversight by an authorized inspector. They concluded that retesting is therefore unnecessary and can lead to costs and operational disruptions because most operators do not have an authorized inspector on staff to oversee that retesting. They further commented that PHMSA should not require pressure vessels be pressure tested or inspected after installation or in situ, because in many cases it may be impracticable or unsafe to do so, especially for pressure vessels used in compressor stations. Finally, AGA *et al.* submitted comments opposing the NPRM's proposed requirement that pressure vessels that have been used prior to being installed or relocated must be retested in place in accordance with Subpart J. They commented that retesting relocated vessels is not required by the ASME BPVC, and that inspection rather than pressure testing is the appropriate method to confirm the integrity of previously-used, relocated pressure vessels.

PST opposed the proposed revisions to § 192.153, contending that PHMSA lacked sufficient technical justification for the proposed changes. PST argued that the ORNL report does not support PHMSA's conclusion that safety would not be adversely affected by NPRM's proposed reduction of the pressure test factor at § 192.153(e). PST asserted that the ORNL report did not conclude that components designed and fabricated under the 2015 edition of the ASME BPVC standards and tested to its lower (1.3 times MAWP) hydrostatic pressure test factor were necessarily as safe as those designed and fabricated to the higher hydrostatic pressure test factor (1.5 times MAWP) in the current text of §§ 192.153(e) and 192.505(b) (which were based on the test factors from the 1998 and prior editions of the ASME BPVC). Rather, PST characterizes the hydrostatic pressure test factor as only ''one of [several] changes between [the] two editions'' (1992 and 2015) compared by the ORNL report that would need to be evaluated to determine the safety impact of the NPRM's revisions to § 192.153 compared to the current PSR. PST also noted that the NPRM proposed applying the lower test factor in the 2015 ASME BPVC not only to components installed since the 2015 edition, but also components installed over the previous decade. Lastly, PST alleged that the NPRM's proposed reduction in the test factor at § 192.153(e) violates the prohibition in 49 U.S.C. 60104(b) on retroactive application of design standards insofar as it purports to impose new design, installation, construction, and testing standards on previously-installed components. PST representatives reiterated their concerns in a conversation with PHMSA personnel after the GPAC meeting.

The GPAC members voted 11–2 in favor of PHMSA's proposed amendments with respect to test requirements for pressure vessels provided that PHMSA make the following changes:

- Clarify in the NPRM's § 192.153(e)(3) that testing or inspection of a pressure vessel must take place after being placed on its supports at its installation location, but may occur prior to tie-in with station piping.
- Clarify in the NPRM's § 192.153(e)(3) that relocated vessels must meet current design and construction requirements, be retested by the operator, and be inspected as described in the previous recommendation, to ensure there are no injurious defects.
- Clarify in a new § 192.153(e)(4) that the retesting requirements applicable to pressure vessels do not apply to those pressure vessels that are used for temporary maintenance and repair activities, such as portable launcher or receivers, temporary odorant tanks, blow down equipment, and other similar equipment, but they must be inspected for safety and integrity prior to usage.

Two GPAC members representing EDF and PST voted against the proposed amendments, expressing concern that the retroactivity prohibition at 49 U.S.C. 60104(b) prohibits PHMSA from applying a revised test factor to existing pressure vessels. During the meeting, PHMSA committed to the GPAC members that it would consider the application of 49 U.S.C. 60104(b)'s prohibition to the changes proposed in the NPRM.

INGAA, AGA, APGA, API, and GPA Midstream submitted joint supplemental comments after the GPAC Meeting supporting the GPAC recommendation and asserting that the proposed PSR amendments did not violate the 49 U.S.C. 60104(b) retroactivity prohibition. GPA Midstream separately submitted supplemental comments on that statutory retroactivity prohibition, explaining by reference to its legislative history, contemporaneous DOT interpretation of the relevant statutory language, and subsequent PHMSA interpretations of the same that 49 U.S.C. 60104(b) prohibits only generically-applicable, retroactive standards imposing new compliance burdens on relevant pipelines. Here, in contrast, GPA Midstream contended the NPRM's proposed revisions to § 192.153(e) would relieve regulatory burdens and operators would have to take no action to be in full compliance with the amended § 192.153(e).

3. PHMSA Response

After considering the comments and the GPAC, PHMSA is adopting the proposed testing requirements for pressure vessels subject to certain amendments to the proposed rule with respect to test requirements for pressure vessels in § 192.153. The final rule adopts the revision to § 192.153(e)(1), which specifies that a prefabricated unit or pressure vessel that is installed after July 13, 2004 is not subject to the strength testing requirements at §§ 192.505(b) provided it has been tested in accordance with § 192.153(a) or (b) and with a test factor of at least 1.3 times the intended MAOP, consistent with the hydrostatic pressure test factors in section VIII, division 1 of the ASME BPVC. The final rule also adds a footnote to table 1 to the § 192.619(a)(2)(ii) MAOP requirements specifying that the factor for establishing the MAOP of a prefabricated unit or pressure vessel installed after July 14, 2004 is 1.3 times the MAOP. These changes ensure that an operator of a pressure vessel designed and hydrostatically tested in accordance with section VIII, division 1 of the ASME BPVC since the incorporation by reference of the 2001 edition of that document is compliant with the PSR. This allows an operator of a pressure vessel designed and hydrostatically tested in accordance with section VIII, division 1 of the ASME BPVC to operate it at an MAOP equal to its design pressure in most instances. PHMSA notes that if the pressure vessel is tested at factor lower than 1.3 times the MAWP under a pneumatic test or under section VIII division 2 of the ASME BPVC, the MAOP of the pipeline must be established such that the test pressure is 1.3 times the MAOP or greater.

PHMSA understands the administrative record shows that this rulemaking's revision of the pressure test factors at § 192.153 does not adversely affect the safety of pressure vessels designed, constructed, and tested in accordance with the 2001 and subsequent editions of the ASME BPVC, and designed, tested, constructed, and operated in accordance with the PSR. PHMSA therefore disagrees with PST's assertion that the ORNL report does not contribute to the technical justification for that change. PST is correct to note that the ORNL report compares the 1992 and 2015 editions of the ASME BPVC, and that other changes have taken place within the intervening editions of that standard (including the 2007 version currently incorporated by reference in the PSR). However, the ORNL report did not provide only a top-level statement of safety equivalence between the 1992 and 2015 editions of the ASME BPVC; it also evaluated the contributions to that ultimate conclusion from each of the material elements of the 1992 and 2015 editions ASME BPVC—including the effects of a reduction in the hydrostatic pressure test factor in ASME BPVC section VIII, division 1 from 1.5 times the MAWP to 1.3 times the MAWP.[58]

The ORNL report predicated its top-level conclusion of safety equivalence across the 1992 and 2015 editions of the BPVC section VIII, division 1, notwithstanding their different hydrostatic pressure test factors, in part on certain shared features. The most important of those features was that both editions' hydrostatic pressure test factors yield hydrostatic pressure testing limits that ensure primary membrane stresses remain at or below plastic collapse stress limits for a pressure vessel, thereby reducing the risk of permanent distortion that would result in rejection of the pressure vessel at qualification. Other features shared between the 1992 and 2015 editions of BPVC section VIII, division 1 contributing to ORNL's safety equivalence finding include the following: Pressure testing by an authorized inspector at qualification verifying leak-tight integrity and the absence of gross deformations and anomalies indicative of design errors, material defects, or weld defects; pressure testing after fabrication verifying leak-tight integrity and the absence of gross deformations and anomalies indicative of design errors, material defects, or weld defects; and overpressure protection in the event of design basis heat exposure ensuring that maximum overpressure does not exceed 1.3 MAWP.

Each of the features listed above are also shared by the 2007 edition of the BPVC section VIII, section 1 incorporated by reference in the PSR, notwithstanding any other differences between that edition and the 1992 and 2015 editions evaluated in the ORNL report. Like the 1992 and 2015 editions, the various design requirements of the 2007 edition of the ASME BPVC ensure that plastic stresses on a pressure vessel remain at or below plastic collapse stress limits to avoid permanent distortion. And like the 1992 and 2015 editions, the 2007 edition backstops that design basis by qualified inspections to identify defects, post-fabrication pressure testing, and overpressure protection from a design basis heat exposure. Insofar as ORNL determined that these shared features contributed to its top-level conclusion of safety equivalence between the 1992 and 2015 editions of the ASME BPVC, PHMSA understands them to support its conclusion in this final rule that that a lower (1.3) test factor will not adversely affect safety.

PHMSA also submits that other elements of this final rule and the PSR's comprehensive safety regime support the conclusion that lowering the test factor to 1.3 will not adversely affect safety. The applicability of the ASME BPVC in the PSR is limited to the design, testing and fabrication of pressure vessels. On the other hand, the PSR applies additional requirements throughout the lifecycle of a pressure vessel to ensure its continued integrity and safe operation. These requirements pertain to construction (subpart G), corrosion control (subpart I), testing (subpart J), operation (subpart L), maintenance (subpart M), and integrity management (subparts O and P) standards. Further, even with respect to design and installation standards that are the focus of ASME BPVC section VIII, division 1, PSR requirements provide additional assurance that stresses remain within safe limits. For example, § 192.201(a)(2)(i) requires overpressure protection devices be set to discharge at 1.1 times MAOP or at a pressure producing a hoop stress of 75 percent of SMYS, whichever is lower—a requirement that is more conservative than analogous overpressure specifications in the ASME BPVC referenced in the ORNL report. Similarly, the ASME BPVC does not specify a minimum pressure test duration. In contrast, the PSR at subpart J requires a minimum pressure test durations of 8 hours (§ 192.505(c)), 4 hours (§ 192.505(d)), 1 hour (§ 192.507(c)), or with a procedure sufficient to ensure discovery of all potentially hazardous leaks (§ 192.509).

PHMSA further notes that exemption in this final rule from subpart J's minimum pressure duration requirements are consistent with that conclusion. Prior to the changes adopted by this final rule, if an operator tested a pressure vessel to 1.3 times the MAOP consistent with section VIII, division 1 of the ASME BPVC rather than 1.5 times the MAOP, it would not comply with the PSR. An operator of such a vessel would need to reduce the MAOP of the pressure vessel such that the test pressure is 1.3 times the reduced MAOP, retest the vessel to 1.5 times the MAOP, or replace the pressure vessel entirely. Likewise, a pressure vessel that was not tested for a duration specified in subpart J would need to be retested or replaced to remain in compliance. While retesting or replacing existing pressure vessels with a longer test duration or higher test factor could conceivably decrease the risk of an overpressure event causing a vessel failure on affected pipelines, PHMSA understands any such safety benefit could be speculative; incident reports indicate that pressure vessel failure has not been an issue on existing vessels in-service.

This is further supported by the conclusions of the ORNL report with respect to the hydrostatic pressure testing limits described above. Further, any potential safety benefit from retesting or replacing pressure vessels already in service would need to be weighed against new safety risks that may emerge from such activity. And here PHMSA understands that re-testing and replacing in-service pressure vessels in pipeline facilities can entail its own safety hazards for operator personnel due to the mass, volume, and installation location of a typical pressure vessel compared with other types of pipeline facilities. Specifically, retesting or replacement of a pressure vessel requires purging of gas, disconnection from local piping, and likely removal from service and reinstallation. The pipeline facilities involved in such efforts may be very heavy and large, which increases hazards to operator personnel when the pressure vessel or other equipment is removed from its installation location and prepared for testing. The layout of compressor stations and other facilities may exacerbate these safety risks if there

[58] ORNL report at Table 9.2 (summarizing Section 7.1.2.1 of the ORNL report on the safety contribution of hydrostatic test factors in different editions of ASME BPVC section VIII, division 1).

is limited space to safely remove the pressure vessel or to maneuver lifting equipment. Each of these steps therefore introduces certain safety risks to operator personnel performing the work that PHMSA believes could outweigh any marginal, speculative safety benefit from re-testing and replacement of previously-installed pressure vessels. Lastly, as pointed out by multiple comments submitted on the NPRM, such re-testing and replacement of existing pipe could entail significant costs and operational disruptions that similarly militate in favor of the exemption in the final rule.

Finally, PHMSA notes that the ASME BPVC does not specify minimum test duration requirements and part 192 does not currently require post-installation inspection of pressure vessels. The final rule's PSR amendment clarifying that these requirements apply to new, replaced, relocated, or otherwise changed pressure vessels installed after the effective date of the final rule are expected to result in an increased level of safety.

The final rule retains the proposed requirement to inspect pre-tested pressure vessels after being placed at the vessel's installation location on its support structure in § 192.153(e)(3). However, consistent with the GPAC's recommendations, the final rule clarifies that those inspections may occur prior to the pressure vessel tie-in on-site with the pipeline. PHMSA appreciates comments that testing vessels after they have been tied-in to station piping may be problematic depending on what or how it is being connected. But one of the risks of transporting pressure vessels and other large components is damage to the vessel including vessel outlets or its support structure while it is being moved within the facility itself. Many of the considerations raised by commenters that may complicate an inspection likewise raise the likelihood of potential damage during installation. For example, it would be unusual for a pressure vessel to be completely inaccessible in a typical compressor station configuration. In addition, since the § 192.153(e)(3) requirement applies to new, replaced, and relocated vessels, operators can ensure access during initial design, construction, and testing stages. The final rule also clarifies that operators must visually inspect the steel structure for damage including, at a minimum: Inlets, outlets, and lifting points. If damage is found, the pressure vessel must be non-destructively tested, re-pressure tested, or remediated in accordance with part 192 and ASME BPVC requirements. Test, inspection, and repair records must be kept for the operational life of the pressure vessel. These clarifying revisions to § 192.153(e)(3) are designed to enhance safety, address the most significant concerns operators had with post-installation inspection, and help ensure that damage incurred during movements within the facility are detected and remediated before the pressure vessel is put into service.

PHMSA has also, consistent with the GPAC's recommendations, clarified when testing and inspection under § 192.153(e)(3) is required. The final rule clarifies that any pressure vessel that is temporarily or permanently installed in a pipeline facility must be inspected for damage as described above unless it has been pressure tested on its supports at its installation location. This includes pressure vessels that are pressure tested by the operator prior to installation when a post-installation pressure test is impracticable (§§ 192.505(d) and 192.507(d) in the final rule) and to pressure vessels where a manufacturer's pressure test is used under § 192.153(e)(4) in the final rule. This change is consistent with pretesting authorizations under § 192.507(d) in the final rule or § 192.505(d) in existing part 192. It preserves the flexibility provided under those authorizations while the post-installation inspection ensures that pre-tested components are not damaged after being tested by the manufacturer or the operator.

The final rule also clarifies design, testing, and inspection requirements for pressure vessels that are relocated. Consistent with the GPAC's recommendations, PHMSA is adding a new § 192.153(e)(6) that clarifies testing and inspection requirements for relocating an existing pressure vessel that has previously been used in service for permanent installation at a new location in a pipeline facility. An operator must have documentation that a relocated pressure vessel meets the design, construction, and testing requirements in place at the time of relocation and pressure test the pressure vessel. If a pre-installation pressure test is performed, the operator must inspect the pressure vessel after installation.

The final rule does not adopt suggestions from commenters to accept a manufacturer's initial pressure test for all relocated pressure vessels. PHMSA did not propose specific changes to the initial pressure testing requirements for relocated, existing pressure vessels. Rather, the requirements in the final rule for permanently relocated vessels complement existing part 192 requirements for relocation of existing facilities with the addition of a new, general requirement in § 192.153(e)(3) to inspect pressure vessels that are not pressure tested in place. Using a manufacturer's initial pressure test of an existing vessel raises safety concerns because the vessel could have been subject to corrosion, fatigue, external force damage, and other threats to the vessel's integrity during its prior operational life or during transportation to the new facility.

The GPAC's discussion noted that operators commonly use such temporary devices for temporary launchers and receivers for integrity assessments and to reduce methane emissions during blowdowns (natural gas is predominately methane, a greenhouse gas). PHMSA did not intend to impair the use of pressure vessels that are relocated temporarily in order to perform maintenance, repair, or emergency-response-related tasks. To prevent this unintended result, PHMSA is incorporating a new § 192.153(e)(4)(ii) to allow the use of a manufacturer's initial test of a pressure vessel temporarily installed in a pipeline facility to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement. This revision addresses temporary and mobile pressure vessels that were discussed during the GPAC meeting, including portable launcher or receivers, temporary odorant tanks, mobile blow down equipment, and other similar equipment. This change reduces barriers to using temporary equipment to perform integrity assessment, maintenance, and pollution mitigation-related tasks (provided the equipment meets the MAOP, design, and inspection requirements in part 192) and thereby is expected to result in greater efficiency for operators and safety and environmental benefits associated with encouraging inspections and repairs. These devices are subject to the new general requirement in § 192.153(e)(3)(ii) to inspect pressure vessels that are not pressure tested in place after installation. Reducing regulatory burdens associated with performing maintenance, repair, emergency response, and pollution abatement tasks could result in safety and environmental benefits by making such actions more attractive to operators.

To prevents misuse of this flexibility, a pressure vessel that is installed under § 192.153(e)(4)(ii) must be removed when the task it is associated with is completed. Operators should define the procedures for employing temporary or mobile pressure vessels in their written procedure manuals. The final rule requires operators to submit a notification to PHMSA and applicable State pipeline safety authorities in accordance with § 192.18 if a temporary pressure vessel must be left in place for longer than 30 days; however, PHMSA does not reference this section in § 192.18(c) and therefore the objection process and advance notice requirements do not apply. Likewise, § 192.153(e)(5) clarifies that an operator is not required to pressure test a pressure vessel that is temporarily removed from a facility to perform a maintenance task and later re-installed at the same location. However, the re-installed pressure vessel must be inspected in accordance with § 192.153(e)(3)(ii) after it is re-installed. Generally, PHMSA does not consider small movements within the same location (*e.g.* within a compressor station) with no other operational changes as a relocation, however the operator should inspect the vessel for damage after installation.

PHMSA has considered the comments by PST and members of the GPAC regarding the nonapplication requirement and finds the revisions to 49 CFR 192.153(e) are not inconsistent with 49 U.S.C. 60104(b). Section 60104(b) provides that a ''design, installation, construction, initial inspection, or initial testing standard does not apply to a pipeline facility existing when the standard is adopted.'' Under the revised § 192.153, operators of existing pressure vessels that meet minimum testing requirements will not be required to take any additional action to comply. While the revised section requires that components be pressure tested with a test factor of at least 1.3 times MAOP, the current § 192.153(e) already required such testing at even higher pressures; in other words, a pressure vessel compliant with the existing § 192.153(e) would also be compliant with § 192.153(e) as revised by this final rule. The revisions to the PSR, therefore, cannot be said to impose a new standard on existing facilities in conflict with 49 U.S.C. 60104(b).

In addition, as described in the preamble to the NPRM, the amendment to 49 CFR 192.153(e) responds to a petition for reconsideration of the Miscellaneous Rule.[59] This final rule addresses the issues raised by the petition challenging the addition of § 192.153(e) in the Miscellaneous Rule pursuant to the reconsideration procedures in part 190. The petition for reconsideration of the Miscellaneous Rule argues PHMSA's modifications to § 192.153 were not merely clarifications regarding the required testing standard for pressure vessels as PHMSA stated in the Miscellaneous Rule, but rather were departures from the testing standard for pressure vessels in the ASME BPVC standard that was incorporated in the regulations at the time. PHMSA maintains that the Miscellaneous Rule merely clarified the required testing standard for pressure vessels, but understands there was ambiguity in the regulations regarding the testing standard for pressure vessels before the Miscellaneous Rule was passed and that the Miscellaneous Rule codified a higher testing standard than many operators reasonably believed was compliant with the regulations at the time. Also, based on the discussion above, PHMSA was able to verify that the provisions in the final rule will not adversely affect safety. PHMSA is therefore allowing pressure vessels tested in accordance with the 1.3 test factor after 2004 to continue operating without retesting in order not to penalize conduct some operators believed complied with the PSR at the time.

Lastly, because PHMSA understands the PSR revisions in this final rule obviate the need for its unpublished October 27, 2015 letter to INGAA announcing a stay of enforcement pertaining to certain pressure vessels in violation of §§ 192.153(e) and 192.505(b), it withdraws that document as of the effective date of this final rule. This letter is also available in the docket for this final rule.

I. Welding Process Requirement (Section 192.229)

1. PHMSA's Proposal

Section 192.229(b) currently bars welders from welding with a welding process if they have not engaged in welding with that same process within the previous six months. GPTC submitted a petition for rulemaking requesting PHMSA revise § 192.229(b) to allow welders to demonstrate they have engaged in welding with a welding process at least twice each calendar year, but at intervals not exceeding 7½ months, provided the welds were tested and found acceptable in accordance with API Standard (Std) 1104.[60] API Std 1104 is the primary standard for welding steel piping and for testing welds on steel pipelines, and covers the requirements for welding and nondestructive testing of pipeline welds. API Std 1104 is used within part 192 requirements for qualifying welders, welding procedures, and welding operators, and interpreting the results of non-destructive tests.

GPTC also noted that the 6-month frequency requirement for the welding process requirement at § 192.229(b) is different than other requirements in § 192.229(c)(1) and (d)(2) governing welder requalification frequency. Those welder requalification requirements demand requalification within the preceding 7½ months, but at least twice each calendar year. GPTC pointed out that this discrepancy between welder process requirements and welder requalification requirements obliged operators either to maintain alternative recordkeeping procedures for the process requirement or perform welds to comply with both the process requirement and the requalification requirements on a 6-month interval. In other words, if a welder wishes to use the same weld to comply with both requirements, they are unable to benefit from the more flexible welder requalification requirements at § 192.229(c)(1) and (d)(2).

PHMSA proposed in the NPRM to revise § 192.229(b) to specify that welders or welding operators may not weld with a particular welding process unless they have engaged in welding with that process within the preceding 7½ months and the welds were tested and found acceptable in accordance with API Std 1104. This change would provide operators some flexibility in scheduling welding activities to maintain welder requalification. PHMSA agrees with GPTC that the proposed revision is more consistent with § 192.229(d)(2). This is potentially beneficial for welders who weld relatively infrequently. PHMSA does not anticipate a decrease in safety, as a 7½-month interval is already permitted for requalification under § 192.229(d)(2)(i), and the change will only affect welders who are not welding throughout the year.

2. Summary of Public Comments

AmeriGas, AIPRO, FreedomWorks, NPGA, Oleksa and Associates, and SPP supported the proposed requalification scheduling for welders. Oleksa and Associates stated that there will be no negative impact on pipeline safety. FreedomWorks stated that the changes would allow welders, many of whom are self-employed freelancers, greater flexibility in their trade. AIPRO commented that the changes would establish regulatory expectations and create more scheduling opportunity for vendors to perform the welding tests and for companies to comply with the standard. The GPAC voted unanimously

[59] Available in docket No. PHMSA–2010–0026 and the docket for this final rule.

[60] Docket No. PHMSA–2014–0015.

in favor of PHMSA's proposed amendments regarding the welding process requirement.

3. PHMSA Response

Based on the comments and the GPAC recommendations, PHMSA has adopted this amendment as proposed. This change will streamline compliance and recordkeeping activities related to § 192.229(b) and will not have a detrimental impact on safety.

J. Pre-Test Applicability (Section 192.507)

1. PHMSA's Proposal

Section 192.505(d) permits operators to test fabricated units and short segments of pipe prior to installation on steel pipelines operated at a hoop stress of 30 percent or more of SMYS if a post-installation test is not practicable. PHMSA proposed in the NPRM to add a new paragraph (d) to § 192.507 to extend this authorization to steel pipelines operated at a hoop stress less than 30 percent of SMYS and at or above 100 psig.[61]

The NPRM's proposed revision is in response to a petition for rulemaking submitted by GPTC for PHMSA to relocate the pre-installation strength testing requirement at § 192.505(d) to the general test requirements in § 192.503 to permit broader application of this authorization. GPTC argued this change would permit operators to use pre-tested pipe and fabricated units in applications outside of higher stress transmission pipelines. GPTC further asserted that as this provision is currently applicable only to higher-stress pipelines operating at a hoop stress at or greater than 30 percent of SMYS, extending the broader pre-testing provision to lower-stress pipelines would not increase pipeline safety risks. Rather, GPTC predicted this proposed change will provide greater flexibility and efficiency for operators of lower-stress pipelines, especially during maintenance activities.

Instead of adding pre-testing provisions to the general requirements at § 192.503 as suggested by the GPTC petition, PHMSA proposed in the NPRM to add § 192.507(d) to permit pre-testing on steel pipelines operating at a hoop stress less than 30 percent of SMYS and at or above 100 psig. The proposal did not extend pre-testing provisions to pipelines operating below 100 psig (§ 192.509), service lines (§ 192.511), or plastic pipelines (§ 192.513). Individual components, excluding short segments of pipe, may still be installed on those facilities with a pre-installation test pursuant to § 192.503(e). PHMSA requested comments on whether it is appropriate to extend pre-testing provisions to such facilities, and solicited proposed requirements that should apply if pre-testing provisions are extended to such facilities.

2. Summary of Public Comments

AmeriGas, NPGA, and SPP supported the proposed changes to § 192.507 to allow operators to extend the authorization for pre-testing fabricated assemblies to include steel pipelines that operate at a hoop stress less than 30 percent of SMYS and at or above 100 psig. Similarly, PST commented that they did not object to extending the pre-testing provisions to lower stress pipelines as proposed in the NPRM.

AGA *et al.,* National Fuel, and Oleksa and Associates recommended that PHMSA consider extending the pre-testing allowance to other pipelines that also pose less of a safety risk. Specifically, they recommended that PHMSA extend the allowance for pre-tested short segments of pipe and fabricated units to steel pipelines that operate at pressures less than 100 psig (§ 192.509), plastic pipelines (§ 192.511), and service lines (§ 192.513) to provide clarity and consistency within the regulations. These commenters suggested the addition of enabling regulatory text. Oleksa and Associates agreed with these commenters, stating that the rationale that applies to permitting pre-tested pipe on steel pipelines operating at a stress less than 30 percent of SMYS and at or above 100 psig applies in the same way to pipelines operating below 100 psig, service lines, and plastic pipelines. They suggested that the simplest way to accomplish this is to modify the wording in § 192.503.

Similarly, NAPSR opposed the proposed revision unless it is revised to allow the use of pre-tested pipe for main repairs under 100 psig. Specifically, NAPSR commented that it may be impracticable to pressure test Type B gathering lines and mains post-installation. They commented that if pre-tested pipe is allowed for systems that operate above 100 psig and above 30 percent SMYS, then pre-tested pipe should also be allowed for all pipe that operates below 100 psig and low stress pipe. NAPSR believes that most operators use pre-tested pipe for main and Type B gathering line repairs as a standard practice; that pipe is soap tested and visually inspected for leaks after installation. They stated that the proposed change in the NPRM could unnecessarily restrict operators from safely and quickly repairing damages, and that distribution operators could potentially experience prolonged outages (especially in cold weather) and increased repair times and cost if pre-tested pipe is not allowed.

AGA *et al.* commented that in 2019, distribution system operators reported 84,608 leaks caused by excavation damage on their Gas Distribution Annual Reports. Assuming each excavation damage related leak required a pressure test, and assuming a cost of $200 per post-installation pressure test, they stated that the cost would be nearly $17 million annually to pressure test pipe replaced due to excavation damage alone. National Fuel's comment included a similar calculation and estimated $8.8 million in cost savings if pre-tested pipe is allowed for such repairs. These commenters asserted that the use of pre-tested pipe would significantly reduce these costs as operators could pre-test full joints or coils of pipe for use on multiple short segment replacements and repairs without compromising safety.

National Fuel commented that extending pre-testing to distribution lines would allow the use of pre-tested pipe for short segment replacements for leak repairs, excavation damage repairs and replacement of visually questionable welds or plastic fusion joints. They noted that without this change operators are required to test short replacement segments in place, which is inefficient, time consuming, and often results in extended shutdown durations and inconvenience to customers. They further stated that based on current regulatory language, an excavation damage repair that involves replacement of two feet of plastic distribution main requires that the operator: (1) Fuse end caps on each end of the replacement segment, (2) pressure test the pipe in place for the required duration, (3) remove the end caps, (4) tie-in the replacement segment by electrofusion or coupling, and (5) purge, gas and soap test the joints. They stated that allowing the use of pre-tested pipe would significantly reduce the repair time and costs to complete the repair and would still result in a pipe segment that is both strength tested and leak tested to ensure an equal level of safety while limiting interruptions to customers.

AGA *et al.* recommended that PHMSA remove the term ''hydrostatic'' from the test requirements for short segments of pipe and pre-fabricated units from § 192.507 because natural gas, inert gas, and air are also allowable test media for pipelines operating at a

[61] ''Pounds per square inch gauge'' refers to internal pressure relative to outside atmospheric pressure.

hoop stress less than 30 percent of SMYS under § 192.503(c).

The GPAC voted unanimously in favor of PHMSA's proposed PSR amendments regarding the welding process requirement but recommended removing the word ''hydrostatic'' from the proposed § 192.507(d).

3. PHMSA Response

Based on the comments received and the recommendation of the GPAC, the final rule adopts the amendments related to pre-testing fabricated assemblies and short segments of pipe as proposed in the NPRM, except that PHMSA has removed the term ''hydrostatic'' from the new § 192.507(d). PHMSA agrees that removing the term ''hydrostatic'' is appropriate since other test media other than water are approved for use in that new section.

The final rule does not extend the authorization in § 192.507 (as revised) for pre-tested segments of pipe and fabricated assemblies beyond steel pipe with an MAOP producing a hoop stress less than 30 percent of SMYS but at or above 100 psig. Operators must still perform leak tests after installing fabricated units and short segments of pipe installed on such pipelines. The remaining categories in subpart J (metallic pipe with an MAOP less than 100 psig, plastic pipe, and service lines) generally represent distribution lines rather than transmission lines. It is not clear that there is adequate safety justification for extending the pre-testing allowance to these categories of lines due to the proximity of such facilities to customers and the differences in design, construction, inspection, and testing requirements for such facilities compared with higher-pressure transmission lines. For example, welds on higher-pressure metallic lines require inspection with non-destructive testing techniques under § 192.241, while plastic pipe joints and welds on lower-pressure metallic lines can be visually inspected instead. The leak tests required for lower-pressure lines in subpart J are, therefore, necessary to ensure the leak-tight integrity of welds and joints on such lines. Commenters did not suggest alternative inspection requirements or other conditions for using pre-tested pipe and fabricated units on such pipelines. PHMSA therefore determined that additional analysis is necessary to consider the safety effects of extending the pre-testing allowance to such facilities, and what, if any, additional conditions may be necessary. The GPAC voted unanimously in favor of this recommended approach. PHMSA may consider this issue in future rulemaking.

PHMSA notes that §§ 192.509, 192.511, and 192.513 require only a leak test. NAPSR presented a scenario where, for a replacement repair, an operator installed pre-tested pipe and then performed a leak test after installation. The leak test described in this scenario meets the post-installation leak test requirement in § 192.509, provided that the operator's test procedure ensures the discovery of all potentially hazardous leaks.

IV. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 80 standards and specifications developed and published by standard development organizations (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices.

The National Technology Transfer and Advancement Act of 1995 (Pub. L. 104–113; NTTAA) directs Federal agencies to use standards developed by voluntary consensus standards bodies in lieu of government-written standards whenever possible. Voluntary consensus standards bodies develop, establish, or coordinate technical standards using agreed-upon procedures. In addition, the Office of Management and Budget (OMB) issued Circular A–119 [62] to implement section 12(d) of the NTTAA relative to the utilization of consensus technical standards by Federal agencies. This circular provides guidance for agencies participating in voluntary consensus standards bodies and describes procedures for satisfying the reporting requirements in the NTTAA.

Accordingly, PHMSA is responsible for determining, via petitions or otherwise, which currently referenced standards should be updated, revised, or removed, and which standards should be added to the PSR. Pursuant to 49 U.S.C. 60102(p), PHMSA may not issue a regulation that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge. Revisions to materials incorporated by reference in the PSR are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials. The Office of the Federal Register issued a rulemaking on November 7, 2014, that revised 1 CFR 51.5 to require that agencies detail in the preamble of an NPRM the ways the materials it proposes to incorporate by reference are reasonably available to interested parties, or how the agency worked to make those materials reasonably available to interested parties.[63]

To meet these obligations for this rulemaking, PHMSA negotiated agreements with API and ASTM to provide viewable copies of standards incorporated by reference in the pipeline safety regulations available to the public at no cost. API Std 1104 is available at *https://www.api.org/products-and-services/standards/rights-and-usage-policy#tab-ibr-reading-room* and is discussed in greater detail in section I.1 of this preamble. The ASTM standards are available at *https://www.astm.org/READINGLIBRARY/* and are discussed in greater detail in section G.1 of this preamble. PHMSA will also provide individual members of the public temporary access to any standard that is incorporated by reference. Requests for access can be sent to the following email address: *phmsaphpstandards@dot.gov.* PHMSA also notes that standards incorporated by reference in the PSR can be obtained from the organization developing each standard. Section 192.7 provides the contact information for each of those standard-developing organizations.

V. Regulatory Analyses and Notices

A. Legal Authority for This Rulemaking

This rule is published under the authority of the Federal Pipeline Safety Law (49 U.S.C. 60101, *et seq.*). Section 60102(a) authorizes the Secretary of Transportation to issue regulations governing the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. Further, § 60102(l) of the Federal Pipeline Safety Law states that the Secretary shall, to the extent appropriate and practicable, update incorporated industry standards that have been adopted as a part of the pipeline safety regulations. The Secretary has delegated the authority in § 60102 to the

[62] OMB, Circular A–119, ''Federal Participation in the Development and Use of Voluntary Consensus Standards and in Conformity Assessment Activities'' (Jan. 27, 2016). Circular A–119 and revisions thereto are available at *https://www.whitehouse.gov/omb/information-for-agencies/circulars/.*

[63] 79 FR 66278.

Administrator of PHMSA in 49 CFR 1.97.

B. Executive Order 12866 and DOT Rulemaking Procedures

E.O. 12866, ''Regulatory Planning and Review,'' [64] requires agencies to regulate in the ''most cost-effective manner,'' to make a ''reasoned determination that the benefits of the intended regulation justify its costs,'' and to develop regulations that ''impose the least burden on society.'' E.O. 12866 and DOT regulations governing rulemaking procedures at 49 CFR part 5 require that PHMSA submit ''significant regulatory actions'' to OMB for review. This rule is considered significant under § 3(f) of E.O. 12866, and was reviewed by OMB. It is also significant under the DOT's rulemaking procedures at 49 CFR part 5.

Similarly, DOT regulations at § 5.5(f)-(g) require that regulations issued by PHMSA and other DOT Operating Administrations ''should be designed to minimize burdens and reduce barriers to market entry whenever possible, consistent with the effective promotion of safety'' and should generally ''not be issued unless their benefits are expected to exceed their costs.''

E.O. 12866 and DOT implementing regulations at 49 CFR 5.5(i) also require PHMSA to provide a meaningful opportunity for public participation, which also reinforces requirements for notice and comment under the Administrative Procedure Act (5 U.S.C. 551, *et seq.*). Therefore, in the NPRM, PHMSA sought public comment on its proposed revisions to the PSR and the preliminary cost and cost savings analyses in the Preliminary RIA, as well as any information that could assist in quantifying the benefits of this rulemaking. Those comments are addressed in this final rule, and additional discussion about the economic impacts of the final rule are provided within the final RIA posted in the rulemaking docket.

PHMSA estimated that this final rule would have economic benefits to the public and the regulated community by reducing unnecessary cost burdens without increasing risks to public safety or the environment. PHMSA estimates that the final rule will result in annualized cost savings of approximately $129.8 million per year, based on a 7 percent discount rate. Most of the quantified cost savings in the final rule are from the revisions to farm tap requirements and the revised atmospheric corrosion reassessment interval for distribution service lines. The final RIA in the rulemaking docket analyzes these economic impacts in detail.

C. Executive Order 13771, ''Reducing Regulation and Controlling Regulatory Cost''

This final rule is an E.O. 13771 [65] deregulatory action. Details on the estimated cost savings of this final rule can be found in the rule's economic analysis within the RIA in the rulemaking docket.

D. Executive Order 13132—''Federalism''

PHMSA analyzed this final rule in accordance with E.O. 13132.[66] E.O. 13132 requires agencies to assure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not impose a substantial direct effect on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government. This final rule also does not impose substantial direct compliance costs on State and local governments.

The final rule could have preemptive effect because the Federal Pipeline Safety Law, specifically 49 U.S.C. 60104(c), prohibits certain State safety regulation of interstate pipelines. Under the Federal Pipeline Safety Law, States may augment pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility PHMSA does not regulate. In this instance, the preemptive effect of the final rule is limited to the minimum level necessary to achieve the objectives of the Federal Pipeline Safety Law under which the final rule is promulgated. Therefore, the consultation and funding requirements of E.O. 13132 do not apply.

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

PHMSA analyzed this final rule in accordance with the principles and criteria in E.O. 13175 [67] and DOT Order 5301.1, ''Department of Transportation Programs, Polices, and Procedures Affecting American Indians, Alaska Natives, and Tribes.'' E.O. 13175 requires agencies to assure meaningful and timely input from Tribal government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities or the relationship and distribution of power between the Federal Government and Tribes. PHMSA assessed the impact of the final rule on Indian Tribal communities and determined that it would not significantly or uniquely affect Tribal communities or Indian Tribal governments. Therefore, the funding and consultation requirements of E.O. 13175 do not apply. PHMSA received no comments to the effect that this rulemaking would have Tribal implications.

F. Executive Order 13211—''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use''

E.O. 13211 [68] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' Under E.O. 13211, a ''significant energy action'' is defined as any action by an agency (normally published in the **Federal Register**) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation (including a notice of inquiry, ANPRM, and NPRM) that: (1)(i) Is a significant regulatory action under E.O. 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

This final rule is not a ''significant energy action'' under E.O. 13211. It is not likely to have a significant adverse effect on supply, distribution, or energy use; rather, it is expected to reduce regulatory burdens on the natural gas pipeline sector without adversely affecting safety. Further, the Office of Information and Regulatory Affairs has not designated this final rule as a significant energy action.

G. Regulatory Flexibility Act and Executive Order 13272

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), as implemented by E.O. 13272, ''Proper Consideration of Small Entities in Agency

[64] 58 FR 51735; Oct. 4, 1993.

[65] 82 FR 9339 (Feb. 3, 2017).

[66] 64 FR 43255 (Aug. 10, 1999).

[67] 65 FR 67249 (Nov. 6, 2000).

[68] 66 FR 28355 (May 22, 2001).

Rulemaking,'' [69] and § 5.13(f) of DOT regulations, requires Federal regulatory agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the Administrative Procedure Act unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities.

PHMSA has determined that the cost-savings in the final rule may result in significant economic impacts on a substantial number of small entities. These impacts on regulated entities are beneficial. PHMSA has included a FRFA within the final RIA posted in the docket for this rulemaking.

H. Paperwork Reduction Act of 1995

The Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) establishes policies and procedures for controlling paperwork burdens imposed by Federal agencies on the public.

Pursuant to 44 U.S.C. 3506(c)(2)(B) and 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. PHMSA expects this final rule to impact the information collections described below.

PHMSA will submit an information collection revision request to OMB for approval based on the requirements in this final rule. The information collections are contained in the PSR. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) current expiration date; (4) type of request; (5) abstract of the information collection activity; (6) description of affected public; (7) estimate of total annual reporting and recordkeeping burden; and (8) frequency of collection. The information collection burden for the following information collections are estimated to be revised as follows:

1. Title: Incident Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0635.

Current Expiration Date: 01/31/2023.

Abstract: This information collection covers the collection of information from gas pipeline operators for incident reporting. PHMSA estimates that due to the revised monetary damage threshold for reporting incidents operators will submit 28 fewer gas distribution incident reports, and 14 fewer gas transmission reports. Operators currently spend 12 hours completing each incident report. Therefore, PHMSA expects to eliminate 42 responses and 504 hours from this information collection per year as a result of the provisions in the proposed rule. PHMSA is also revising PHMSA F 7100.1, the Gas Distribution Incident Report, to collect data on mechanical joint failures that arise to the level of an incident as stipulated in 49 CFR 191.3. PHMSA does not expect operators to incur additional burden due to this change.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 259.

Total Annual Burden Hours: 3,108.

Frequency of Collection: On Occasion.

2. Title: Annual and Incident Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 01/31/2023.

Abstract: This information collection covers the collection of information from gas pipeline operators for immediate notice of incidents and Annual reports. Based on the proposals in this rule, PHMSA plans to eliminate the MFF report form under this OMB Control Number and have operators submit the annual total of mechanical joint failures on the Gas Distribution Annual Report under OMB Control Number 2137–0629. In the currently-approved information collection, it is estimated that PHMSA currently receives, on average, 8,300 MFF reports each year with each operator spending, on average, 1 hour to complete each report. By eliminating this report, PHMSA plans to reduce the burden for this information collection by 8,300 responses and 8,300 burden hours.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 2,247.

Total Annual Burden Hours: 71,801.

Frequency of Collection: Regular.

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

OMB Control Number: 2137–0625.

Current Expiration Date: 06/30/2022.

Abstract: The PSR require operators of gas distribution pipelines to develop and implement IM programs.

PHMSA proposed to eliminate this requirement for master meter operators. Based on the currently approved information collection, PHMSA estimates that, on average, 5,461 master meter operators spend 26 hours, annually, developing new IM plans and/or updating their existing IM plans. Eliminating this requirement for master meter operators will eliminate recordkeeping burdens attributable to these 5,461 existing master meter operators, saving 141,986 hours of burden annually.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,882.

Total Annual Burden Hours: 723,192.

Frequency of Collection: On occasion.

4. Title: Gas Distribution Annual Report.

OMB Control Number: 2137–0629.

Current Expiration Date: 10/31/2021.

Abstract: The PSR require distribution operators to prepare and submit annual reports with summary information on their pipeline infrastructure. PHMSA proposed to shift the mechanical fitting failure form requirements to a count of hazardous leaks involving a failure of a mechanical joint on the distribution annual report form. PHMSA estimates that it will take gas distribution operators approximately 30 minutes (0.5 hours; calculated as 13,075 mechanical joint failures divided by 1,446 operators times 3 minutes per mechanical joint failure) to add this information to the annual report. As a result, the burden for this information collection will increase by approximately 723 hours. This addition will have no effect on the total number of reports submitted.

Affected Public: Natural Gas Distribution Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,446.

Total Annual Burden Hours: 25,305.

Frequency of Collection: Annually.

I. Unfunded Mandates Reform Act of 1995

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

PHMSA prepared a final RIA and determined that this final rule does not impose enforceable duties on State, local, or Tribal governments or on the private sector of $164 million in 2019 dollars or more in any one year. A copy of the final RIA is available for review in the docket of this rulemaking.

[69] 68 FR 7990 (Feb. 19, 2003).

J. National Environmental Policy Act

The National Environmental Policy Act (NEPA) (42 U.S.C. 4321 *et. seq.*) requires Federal agencies to prepare a detailed statement on major Federal actions significantly affecting the quality of the human environment.

PHMSA analyzed this rule in accordance with NEPA, NEPA implementing regulations (40 CFR parts 1500–1508), and DOT Order 5610.1C. PHMSA prepared a draft environmental assessment (EA) for the NPRM and posted it in the rulemaking docket; PHMSA received no comments on the draft EA. For this final rule, PHMSA has prepared a Final Environmental Assessment (EA) and has determined that this final rule will not significantly affect the quality of the human environment. The final EA for this final rule is available in the docket.

K. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in the spring and fall of each year. The RIN number contained in the heading of this document is a cross-reference for this action to the Unified Agenda.

List of Subjects

49 CFR Part 191

Pipeline reporting requirements, Integrity management, Pipeline safety, Gas gathering.

49 CFR Part 192

Incorporation by reference, Pipeline safety, Fire prevention, Security measures.

In consideration of the forgoing, PHMSA is amending 49 CFR parts 191 and 192 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS

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

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

■ 2. In § 191.3, in the definition of ''Incident'' revise paragraph (1)(ii) to read as follows:

§ 191.3 Definitions.

* * * * *

Incident means any of the following events:

(1) * * *

(ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.

* * * * *

■ 3. In § 191.11, revise paragraph (b) to read as follows:

§ 191.11 Distribution system: Annual Report.

* * * * *

(b) *Not required.* The annual report requirement in this section does not apply to a master meter system, a petroleum gas system that serves fewer than 100 customers from a single source, or an individual service line directly connected to a production pipeline or a gathering line other than a regulated gathering line as determined in § 192.8.

§ 191.12 [Removed and Reserved]

■ 4. Remove and reserve § 191.12.

■ 5. Appendix A to part 191 is added to read as follows:

Appendix A to Part 191—Procedure for Determining Reporting Threshold

I. Property Damage Threshold Formula

Each year after calendar year 2021, the Administrator will publish a notice on PHMSA's website announcing the updates to the property damage threshold criterion that will take effect on July 1 of that year and will remain in effect until the June 30 of the next year. The property damage threshold used in the definition of an *Incident* at § 191.3 shall be determined in accordance with the following formula:

$$T_r = T_p \times \frac{CPI_r}{CPI_p}$$

Where:

T_r is the revised damage threshold,
T_p is the previous damage threshold,
CPI_r is the average Consumer Price Indices for all Urban Consumers (CPI–U) published by the Bureau of Labor Statistics each month during the most recent complete calendar year, and
CPI_p is the average CPI–U for the calendar year used to establish the previous property damage criteria.

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

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

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

■ 6. In § 192.7:

■ a. Revise paragraph (a), paragraph (b) introductory text, and paragraph (b)(9);

■ b. Remove and reserve paragraph (c)(7); and

■ c. Revise paragraph (e) introductory text and paragraphs (e)(11) and (20).

The revisions read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. All approved material is available for inspection at Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590, 202–366–4046 *https://www.phmsa.dot.gov/pipeline/regs,* and is available from the sources listed in the remaining paragraphs of this section. It is also available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email *fedreg.legal@nara.gov* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html.*

(b) American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202–682–8000, website: *https://www.api.org/.*

* * * * *

(9) API Standard 1104, ''Welding of Pipelines and Related Facilities,'' 20th edition, October 2005, including errata/addendum (July 2007) and errata 2 (2008), (API Std 1104), IBR approved for §§ 192.225(a); 192.227(a); 192.229(b) and (c); 192.241(c); and Item II, Appendix B.

* * * * *

(e) ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832–9585, website: *http://astm.org.*

* * * * *

(11) ASTM D2513–18a, ''Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings,'' approved August 1, 2018, (ASTM D2513), IBR approved for Item I, Appendix B to Part 192.

* * * * *

(20) ASTM F2620–19, ''Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings,'' approved February 1, 2019, (ASTM

F2620), IBR approved for §§ 192.281(c) and 192.285(b).

* * * * *

■ 7. In § 192.121:

■ a. In the first sentence of paragraph (a), remove the words ''*Design formula.* Design formulas for plastic pipe are'' and add in their place the words ''*Design pressure.* The design pressure for plastic pipe is'';

■ b. In paragraph (c)(2) introductory text add the words ''on or'' after the word ''produced'';

■ c. Revise paragraphs (c)(2)(iii) and (iv), and (d)(2)(iv);

■ d. In paragraph (e) introductory text add the words ''on or'' after the word ''produced''; and

■ e. Revise paragraph (e)(4).

The revisions read as follows:

§ 192.121 Design of plastic pipe.

* * * * *

(c) * * *

(2) * * *

(iii) The pipe has a nominal size (IPS or CTS) of 24 inches or less; and

(iv) The wall thickness for a given outside diameter is not less than that listed in table 1 to this paragraph (c)(2)(iv).

TABLE 1 TO PARAGRAPH (c)(2)(iv)

PE pipe: minimum wall thickness and SDR values		
Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
½″ CTS	0.090	7
½″ IPS	0.090	9.3
¾″ CTS	0.090	9.7
¾″ IPS	0.095	11
1″ CTS	0.099	11
1″ IPS	0.119	11
1¼″ IPS	0.151	11
1½″ IPS	0.173	11
2″	0.216	11
3″	0.259	13.5
4″	0.265	17
6″	0.315	21
8″	0.411	21
10″	0.512	21
12″	0.607	21
16″	0.762	21
18″	0.857	21
20″	0.952	21
22″	1.048	21
24″	1.143	21

(d) * * *

(2) * * *

(iv) The minimum wall thickness for a given outside diameter is not less than that listed in table 2 to paragraph (d)(2)(iv):

TABLE 2 TO PARAGRAPH (d)(2)(iv)

PA–11 pipe: minimum wall thickness and SDR values		
Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
½″ CTS	0.090	7.0
½″ IPS	0.090	9.3
¾″ CTS	0.090	9.7
¾″ IPS	0.095	11
1″ CTS	0.099	11
1″ IPS	0.119	11
1¼ IPS	0.151	11
1½″ IPS	0.173	11
2″ IPS	0.216	11
3″ IPS	0.259	13.5
4″ IPS	0.333	13.5
6″ IPS	0.491	13.5

(e) * * *

(4) The minimum wall thickness for a given outside diameter is not less than that listed in table 3 to paragraph (e)(4).

TABLE 3 TO PARAGRAPH (e)(4)

PA–12 pipe: minimum wall thickness and SDR values		
Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
½″ CTS	0.090	7
½″ IPS	0.090	9.3
¾″ CTS	0.090	9.7
¾″ IPS	0.095	11
1″ CTS	0.099	11
1″ IPS	0.119	11
1¼″ IPS	0.151	11
1½″ IPS	0.173	11
2″ IPS	0.216	11
3″ IPS	0.259	13.5
4″ IPS	0.333	13.5
6″ IPS	0.491	13.5

* * * * *

■ 8. In § 192.153 revise paragraphs (b) and paragraph (e) to read as follows:

§ 192.153 Components fabricated by welding.

* * * * *

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with the ASME BPVC (*Rules for Construction of Pressure Vessels* as defined in either Section VIII, Division 1 or Section VIII, Division 2; incorporated by reference, *see* § 192.7), except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

* * * * *

(e) The test requirements for a prefabricated unit or pressure vessel, defined for this paragraph as components with a design pressure established in accordance with paragraph (a) or paragraph (b) of this section are as follows.

(1) A prefabricated unit or pressure vessel installed after July 14, 2004 is not subject to the strength testing requirements at § 192.505(b) provided the component has been tested in accordance with paragraph (a) or paragraph (b) of this section and with a test factor of at least 1.3 times MAOP.

(2) A prefabricated unit or pressure vessel must be tested for a duration specified as follows:

(i) A prefabricated unit or pressure vessel installed after July 14, 2004, but before October 1, 2021 is exempt from §§ 192.505(c) and (d) and 192.507(c) provided it has been tested for a duration consistent with the ASME BPVC requirements referenced in paragraph (a) or (b) of this section.

(ii) A prefabricated unit or pressure vessel installed on or after October 1, 2021 must be tested for the duration specified in either § 192.505(c) or (d), § 192.507(c), or § 192.509(a), whichever is applicable for the pipeline in which the component is being installed.

(3) For any prefabricated unit or pressure vessel permanently or temporarily installed on a pipeline facility, an operator must either:

(i) Test the prefabricated unit or pressure vessel in accordance with this section and Subpart J of this part after it has been placed on its support structure at its final installation location. The test may be performed before or after it has been tied-in to the pipeline. Test records that meet § 192.517(a) must be kept for the operational life of the prefabricated unit or pressure vessel; or

(ii) For a prefabricated unit or pressure vessel that is pressure tested prior to installation or where a manufacturer's pressure test is used in accordance with paragraph (e) of this section, inspect the prefabricated unit or pressure vessel after it has been placed on its support structure at its final installation location and confirm that the prefabricated unit or pressure vessel was not damaged during any prior operation, transportation, or installation into the pipeline. The inspection procedure and documented inspection must include visual inspection for vessel damage, including, at a minimum, inlets, outlets, and lifting locations. Injurious defects that are an integrity threat may include dents, gouges, bending, corrosion, and cracking. This inspection must be performed prior to operation but may be performed either before or after it has been tied-in to the pipeline. If injurious defects that are an integrity threat are found, the prefabricated unit or pressure vessel must be either non-destructively tested, re-pressure tested, or remediated in accordance with applicable part 192 requirements for a fabricated unit or with the applicable ASME BPVC requirements referenced in paragraphs (a) or (b) of this section. Test, inspection, and repair records for the fabricated unit or pressure vessel must be kept for the operational life of the component. Test records must meet the requirements in § 192.517(a).

(4) An initial pressure test from the prefabricated unit or pressure vessel manufacturer may be used to meet the requirements of this section with the following conditions:

(i) The prefabricated unit or pressure vessel is newly-manufactured and installed on or after October 1, 2021, except as provided in paragraph (e)(4)(ii) of this section.

(ii) An initial pressure test from the fabricated unit or pressure vessel manufacturer or other prior test of a new or existing prefabricated unit or pressure vessel may be used for a component that is temporarily installed in a pipeline facility in order to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement. The temporary component must be promptly removed after that task is completed. If operational and environmental constraints require leaving a temporary prefabricated unit or pressure vessel under this paragraph in place for longer than 30 days, the operator must notify PHMSA and State or local pipeline safety authorities, as applicable, in accordance with § 192.18.

(iii) The manufacturer's pressure test must meet the minimum requirements of this part; and

(iv) The operator inspects and remediates the prefabricated unit or pressure vessel after installation in accordance with paragraph (e)(3)(ii) of this section.

(5) An existing prefabricated unit or pressure vessel that is temporarily removed from a pipeline facility to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement, and then re-installed at the same location must be inspected in accordance with paragraph (e)(3)(ii) of this section; however, a new pressure test is not required provided no damage or threats to the operational integrity of the prefabricated unit or pressure vessel were identified during the inspection and the MAOP of the pipeline is not increased.

(6) Except as provided in paragraphs (e)(4)(ii) and (5) of this section, on or after October 1, 2021, an existing prefabricated unit or pressure vessel relocated and operated at a different location must meet the requirements of this part and the following:

(i) The prefabricated unit or pressure vessel must be designed and constructed in accordance with the requirements of this part at the time the vessel is returned to operational service at the new location; and

(ii) The prefabricated unit or pressure vessel must be pressure tested by the operator in accordance with the testing and inspection requirements of this part applicable to newly installed prefabricated units and pressure vessels.

■ 9. In § 192.229, revise paragraph (b) to read as follows:

§ 192.229 Limitations on welders and welding operators.

* * * * *

(b) A welder or welding operator may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder or welding operator was engaged in welding with that process. Alternatively, welders or welding operators may demonstrate they have engaged in a specific welding process if they have performed a weld with that process that was tested and found acceptable under section 6, 9, 12, or Appendix A of API Std 1104 (incorporated by reference, *see* § 192.7) within the preceding 7½ months.

* * * * *

■ 10. In § 192.281, revise paragraph (c) to read as follow:

§ 192.281 Plastic Pipe.

* * * * *

(c) *Heat-fusion joints.* Each heat fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620 (incorporated by reference in § 192.7), or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by test or experience to produce strong gastight joints, and the following:

* * * * *

■ 11. In § 192.283 revise paragraph (a)(3) to read as follows:

§ 192.283 Plastic pipe: Qualifying joining procedures.

(a) * * *

(3) For procedures intended for non-lateral pipe connections, perform tensile testing in accordance with a listed specification. If the test specimen elongates no less than 25% or failure initiates outside the joint area, the procedure qualifies for use.

* * * * *

■ 12. In § 192.285, revise paragraph (b) to read as follows

§ 192.285 Plastic pipe: Qualifying persons to make joints.

* * * * *

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under § 192.283(a), and for PE heat fusion joints (except for electrofusion joints) visually inspected in accordance with ASTM F2620 (incorporated by reference, see § 192.7), or a written procedure that has been demonstrated to provide an equivalent or superior level of safety, applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

* * * * *

■ 13. In § 192.465, revise paragraph (b) to read as follows:

§ 192.465 External corrosion control: Monitoring.

* * * * *

(b) Cathodic protection rectifiers and impressed current power sources must be periodically inspected as follows:

(1) Each cathodic protection rectifier or impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier.

(2) After January 1, 2022, each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding 15 months.

* * * * *

■ 14. In § 192.481, revise paragraph (a) and add paragraph (d) to read as follows:

§ 192.481 Atmospheric corrosion control: Monitoring.

(a) Each operator must inspect and evaluate each pipeline or portion of the pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

Pipeline type:	Then the frequency of inspection is:
(1) Onshore other than a Service Line	At least once every 3 calendar years, but with intervals not exceeding 39 months.
(2) Onshore Service Line	At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section.
(3) Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

* * * * *

(d) If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months.

■ 15. In 192.491, revise paragraph (c) to read as follows:

§ 192.491 Corrosion control records.

* * * * *

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years with the following exceptions:

(1) Operators must retain records related to §§ 192.465(a) and (e) and 192.475(b) for as long as the pipeline remains in service.

(2) Operators must retain records of the two most recent atmospheric corrosion inspections for each distribution service line that is being inspected under the interval in § 192.481(a)(2).

■ 16. In § 192.505, revise paragraph (c) to read as follows

§ 192.505 Strength test requirements for steel pipelines to operate at a hoop stress of 30 percent or more of SMYS.

* * * * *

(c) Except as provided in paragraph (d) of this section, the strength test must be conducted by mai ntaining the pressure at or above the test pressure for at least 8 hours.

* * * * *

■ 17. In § 192.507, add paragraph (d) to read as follows:

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

* * * * *

(d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a pre-installation hydrostatic pressure test must be conducted in accordance with the requirements of this section.

■ 18. In § 192.619, revise Table 1 to paragraph (a)(2)(ii) to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

* * * * *

(a) * * *

(2) * * *

(ii) * * *

TABLE 1 TO PARAGRAPH (a)(2)(ii)

Class location	Installed before (Nov. 12, 1970)	Factors,[1 2] segment— Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1] For offshore pipeline segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

[2] For a component with a design pressure established in accordance with § 192.153(a) or (b) installed after July 14, 2004, the factor is 1.3.

■ 19. In § 192.740, revise the section heading, paragraph (a) and paragraph (c) to read as follows:

§ 192.740 Pressure regulating, limiting, and overpressure protection—Individual service lines directly connected to regulated gathering or transmission pipelines.

(a) This section applies, except as provided in paragraph (c) of this section, to any service line directly connected to a transmission pipeline or regulated gathering pipeline as determined in § 192.8 that is not operated as part of a distribution system.

* * * * *

(c) This section does not apply to equipment installed on:

(1) A service line that only serves engines that power irrigation pumps;

(2) A service line included in a distribution integrity management plan meeting the requirements of subpart P of this part; or

(3) A service line directly connected to either a production or gathering pipeline other than a regulated gathering line as determined in § 192.8 of this part.

■ 20. Revise § 192.1003 to read as follows:

§ 192.1003 What do the regulations in this subpart cover?

(a) *General.* Unless exempted in paragraph (b) of this section, this subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator must follow the requirements in this subpart.

(b) *Exceptions.* This subpart does not apply to:

(1) Individual service lines directly connected to a production line or a gathering line other than a regulated onshore gathering line as determined in § 192.8;

(2) Individual service lines directly connected to either a transmission or regulated gathering pipeline and maintained in accordance with § 192.740(a) and (b); and

(3) Master meter systems.

■ 21. In § 192.1005, revise the section heading to read as follows:

§ 192.1005 What must a gas distribution operator (other than a small LPG operator) do to implement this subpart?

* * * * *

■ 22. In § 192.1007, revise paragraph (b) to read as follows:

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

* * * * *

(b) *Identify threats.* The operator must consider the following categories of threats to each gas distribution pipeline: Corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other issues that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats.

Sources of data may include incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

* * * * *

§ 192.1009 [Removed and Reserved]

■ 23. Remove and reserve § 192.1009.

■ 24. In § 192.1015, revise the section heading, and paragraphs (a) and (b) to read as follows:

§ 192.1015 What must a small LPG operator do to implement this subpart?

(a) *General.* No later than August 2, 2011, a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph (b) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

(b) *Elements.* A written integrity management plan must address, at a minimum, the following elements:

(1) *Knowledge.* The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

(2) *Identify threats.* The operator must consider, at minimum, the following categories of threats (existing and potential): Corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.

(3) *Rank risks.* The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.

(4) *Identify and implement measures to mitigate risks.* The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.

(5) *Measure performance, monitor results, and evaluate effectiveness.* The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.

(6) *Periodic evaluation and improvement.* The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every 5 years. The operator must consider the results of the performance monitoring in these evaluations.

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Appendix B to Part 192 [Amended]

■ 25. Amend Appendix B to part 192 as follows:

■ a. In section I.A., remove the entry for ''ASTM D2513–12ae1'' and add in its place a new entry for ''ASTM D2513'', and

■ b. In Section I.B., remove the entry for ''ASTM D2513–12ae1'' and add in its place a new entry for ''ASTM D2513''.

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Howard R. Elliott,

Administrator.

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