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DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA-2018-0046]

RIN 2137-AF36

Pipeline Safety: Gas Pipeline Regulatory Reform

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

ACTION: Notice of proposed rulemaking.

SUMMARY: PHMSA is seeking comments on proposed amendments to the Federal Pipeline Safety Regulations that are intended to ease regulatory burdens on the construction, maintenance and operation of gas transmission, distribution, and gathering pipeline systems. The amendments in this proposal are based on PHMSA's considered review of public comments, petitions for rulemaking, and an agency initiative to identify appropriate areas where regulations might be repealed, replaced, or modified.

DATES: Submit comments by **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

ADDRESS: Submit comments, identified by Docket No. PHMSA-2018-0046, using any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Fax:* 1-202-493-2251.

- *Mail:* U.S. DOT Docket Management System, West Building Ground Floor, Room W12-140, 1200 New Jersey Avenue SE, Washington, DC 20590-0001.
- *Hand-deliver/courier*: Available between 9:00 a.m. and 5:00 p.m., Monday through Friday, except federal holidays.

Instructions: All submissions must include the agency name and docket number for this notice of proposed rulemaking. If you submit your comments by mail, submit two copies. If you wish to receive confirmation that PHMSA has received your comments by mail, include a self-addressed stamped postcard.

Privacy Act: In accordance with 5 U.S.C. 553(c), the DOT solicits comments from the public. The DOT posts these comments, without edit, including any personal information the commenter provides, to http://www.regulations.gov. The complete privacy statement can be reviewed at http://www.dot.gov/privacy.

Confidential Business Information

Confidential Business Information (CBI) is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (FOIA) (5 U.S.C. 552), CBI is exempt from public disclosure. If your comments responsive to this notice contain commercial or financial information that is customarily treated as private, that you actually treat as private, and that is relevant or responsive to this notice, it is important that you clearly designate the submitted comments as CBI. Pursuant to 49 CFR 190.343, you may ask PHMSA to give confidential treatment to information you give to the agency by taking the following steps: (1) mark each page of the original document submission containing CBI as “Confidential”; (2) send PHMSA, along with the original document, a second copy of the original document with the CBI deleted;

and (3) explain why the information you are submitting is CBI. Unless you are notified otherwise, PHMSA will treat such marked submissions as confidential under the Freedom of Information Act, and they will not be placed in the public docket of this notice. Submissions containing CBI should be sent to Sayler Palabrica at DOT, PHMSA, PHP-30, 1200 New Jersey Avenue, SE, PHP-30, Washington, DC 20590-0001. Any commentary PHMSA receives that is not specifically designated as CBI will be placed in the public docket for this matter.

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 proposing to amend the Federal Pipeline Safety Regulations (PSR) at 49 CFR parts 191 and 192 to adopt several actions that ease regulatory burdens on the construction, operation, and maintenance of gas transmission, distribution, and gathering pipeline systems. These proposed amendments include regulatory relief actions identified by internal agency review, petitions for rulemaking, and public comments submitted in response to the Department of Transportation (DOT) infrastructure and regulatory reform notices: "Transportation Infrastructure: Notice of Review of Policy, Guidance, and Regulation" (82 FR 26734; June 8, 2017), and "Notification of Regulatory Review" (82 FR 45750; Oct. 2, 2017). PHMSA is requesting input from the public on the proposed amendments.

B. Proposed Amendments

PHMSA is proposing the following amendments to parts 191 and 192:

A. Provide flexibility in the inspection requirements for farm taps;

B. Repeal distribution integrity management program (DIMP) requirements for master meter operators;

C. Repeal submission requirements for the mechanical fitting failure (MFF) reports;

D. Adjust the monetary damage threshold for reporting incidents for inflation;

E. Allow remote monitoring of rectifier stations;

F. Revise the inspection interval for monitoring atmospheric corrosion on gas distribution service pipelines;

G. Update the design standard for polyethylene (PE) pipe and raise the maximum diameter limit;

H. Revise test requirements for pressure vessels consistent with American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME BPVC);

I. Revise welder requalification requirements to provide scheduling flexibility; and

J. Extend the allowance for pre-tested short segments of pipe and fabricated units to pipelines operating at a hoop stress less than 30 percent of the specified minimum yield strength (SMYS) and above 100 pounds per square inch (psi).

C. Costs and Benefits

In accordance with 49 U.S.C. 60102, Executive Order (E.O.) 12866, and DOT policy, PHMSA has prepared an initial assessment of the costs and benefits of these proposed changes as well as reasonable alternatives. PHMSA has released the preliminary regulatory impact analysis (PRIA) concurrent with this NPRM for public review and comment, and it is available in the docket.

The PRIA uses an analysis period of twenty years and the incremental cost savings are assumed to accrue on an ongoing basis. Most of the proposed revisions are deregulatory that are expected to reduce unnecessary regulatory burdens, increaseflexibility and efficiency, and add clarity to existing regulations. PHMSA estimates the value of the total quantified annualized cost savings is approximately $129 million (at a discount rate of 7 percent) or approximately $132 million (at a discount rate of 3 percent).[1] PHMSA describes the benefits of this proposed rule qualitatively and does not anticipate that the revisions will result in an adverse impact on pipeline safety.

The primary economic consequences of the proposed deregulatory actions in this rule are cost savings. The largest quantified cost savings are due to the amendments related to farm taps and atmospheric corrosion (AC). The remaining amendments provide benefits largely of convenience, clarity and simplicity. The total estimated economic effects of the proposed rule are summarized in the table below (Table 1). PHMSA provided annualized estimates of cost savings where available.

Table 1: Total Estimated Discounted Cost Savings

Category	Estimated Cost Savings (millions)
Total (20 years; discounted at 7 percent)	$1,371.4
Total (20 years; discounted at 3 percent	$1,965.3

[1] Both values are in 2018 dollars.

Annualized (discounted at 7 percent)	$129.45
Annualized (discounted at 3 percent)	$132.101

II. Background

On January 30, 2017, the President issued E.O. 13771, "Reducing Regulation and Controlling Regulatory Costs." E.O. 13771 explained the executive branch's regulatory policy to be prudent and financially responsible in the expenditure of funds, from both public and private sources, and to manage the compliance burdens from federal regulations.

On February 24, 2017, the President issued E.O. 13777, "Enforcing the Regulatory Reform Agenda" (82 FR 12285), which established a federal policy to "alleviate unnecessary regulatory burdens placed on the American people." E.O. 13777 required that each federal agency establish a Regulatory Reform Task Force (RRTF) to evaluate existing regulations and "make recommendations to the agency head regarding their repeal, replacement, or modification." Each RRTF must identify unnecessary, outdated, inneffective regulations and those that impose costs that exceed benefits.

On March 28, 2017, the President issued E.O. 13783, "Promoting Energy Independence and Economic Growth" (82 FR 16093; Mar. 28, 2017), to promote the clean and safe development of the Nation's energy resources by eliminating unnecessary regulatory burdens on energy production, economic growth, and job creation. E.O. 13783 tasked agencies to review existing regulations, guidance, and orders that potentially burden the development or use of domestically produced energy resources. Specifically, agencies must look for impacts on siting, permitting, production, utilization, transmission, or delivery of energy resources and encourage the development of recommendations to reduce or eliminate potential burdens.

DOT issued two notices in response to the three executive orders soliciting regulatory reform ideas from the public. The first notice (82 FR 26734; June 8, 2017) requested public comment on existing regulations that may be obstacles to transportation infrastructure projects. DOT received more than 200 comments in the transportation infrastructure docket, including 6 comments that are relevant to the PSR.[2] The second notice (82 FR 45750; Oct. 2, 2017) requested comment on existing rules and other agency actions that may be eligible for repeal, replacement, suspension, or modification without compromising safety. DOT asked the public to identify agency actions that eliminate jobs or inhibit job creation; are outdated, unnecessary, or ineffective; impose costs that exceed benefits; create a serious inconsistency or otherwise interferes 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, (82 FR 51178; Nov. 3, 2017). Of the nearly 3,000 public comments received, approximately 30 were related to the federal PSR.[3]

To support DOT's regulatory reform efforts, PHMSA's Office of Pipeline Safety (OPS) reviewed, considered, and identified existing regulations that could be improved, revised, repealed, or streamlined. OPS also considered the public comments submitted in response to DOT's June 8, 2017, notice soliciting comments about transportation infrastructure, DOT's October 2, 2017, public notice soliciting comments on regulatory reform, and petitions for rulemakings. Some of the comments submitted in response to these notices are addressed in this proposed rule, such as the proposed amendments to reporting requirements, farm tap maintenance, atmospheric corrosion monitoring. Other comments

[2] Docket No. DOT-OST-2017-0057
[3] Docket No. DOT-OST-2017-0069

will be addressed in other rulemaking projects, or through revised policy and guidance. Finally, some ideas proposed in comments are under longer-term technical review or have been rejected due to safety concerns.

III. Request for Input

PHMSA is seeking public comments on the regulatory reform actions proposed in this notice. PHMSA will consider all relevant, substantive comments but encourages interested parties to submit comments that: (1) identify the proposed amendments being commented on and the appropriate section numbers; (2) provide justification for their support or opposition to the proposed amendments, especially data on safety risks and cost burdens; and (3) provide specific alternatives if appropriate.

IV. Proposed Amendments

Distribution Integrity Management Program (DIMP)

On December 4, 2009, PHMSA issued a final rule, titled "Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines" (74 FR 63905), creating 49 CFR part 192, subpart P. The scope of subpart P, defined at § 192.1003, requires certain gas distribution operators to develop and implement integrity management (IM) programs. PHMSA is proposing two revisions to DIMP requirements to ease or eliminate regulatory burdens on certain gas distribution operators. The first revision is to allow operators of individual service lines directly connected to transmission or regulated gathering lines (commonly known as "farm taps") the option of managing the maintenance of pressure regulating devices under either § 192.740 or their DIMP plan in accordance with subpart P. As part of this amendment, the proposed rule would also exempt farm taps originating from unregulated gathering and production pipelines from DIMP, § 192.740, and incident and annual reporting requirements in part 191. Second, PHMSA is also proposing to exempt master meter operators from DIMP requirements due to their simplicity.

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

PHMSA proposes 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. A "farm tap" is the common name for an individual gas service line directly connected to a gas transmission, production, or gathering pipeline. The term farm tap is not a regulatory definition used in the PSR, however a portion of a farm tap between the first aboveground point where downstream piping can be isolated from source piping (e.g. a valve or regulator inlet) and 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 the definition of a "service line" in § 192.3).

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" (82 FR 7972). 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). Such devices must currently be inspected and tested at least once every 3 calendar years, not to exceed 39 months. Further, PHMSA revised the DIMP applicability regulations at § 192.1003 to exclude farm taps from DIMP requirements. PHMSA amended part 192 as such to create uniform compliance requirements for farm taps and decrease the burden of meeting the DIMP requirements. However, operators who historically had included farm taps in their DIMP plan found it burdensome to remove those facilities from their plan and reevaluate the risks under a new program.

DOT received joint comments on its regulatory reform notice (82 FR 45750; Oct. 2, 2017) 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, PHMSA is proposing to revise §§ 192.740 and 192.1003 to give operators of farm taps originating from regulated source pipelines the choice to include those farm taps in their DIMP or manage the maintenance of the associated pressure regulators under the requirements at § 192.740. PHMSA has determined that compliance with either § 192.740 or DIMP provides an equivalent level of safety. PHMSA, therefore anticipates that this action will maintain pipeline safety while reducing regulatory burden. As an alternative to the proposal submitted in public comments, PHMSA also evaluated the alternative of repealing § 192.740 and reinstating DIMP requirements for farm taps. However, that alternative only shifts the problem onto transmission and gathering operators with no safety benefit.

Finally, PHMSA proposes to exempt farm taps branching off of 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 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 production pipeline with an attached farm tap must have an operator identification number in accordance with § 191.22 and must submit incident reports for incidents caused by failures on the service pipeline (§ 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.

B. Master Meter Operators (Sections 192.1003, 192.1015)

PHMSA is proposing to revise §§ 192.1003 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 meters include owners of apartment complexes or mobile home parks who sell gas to tenants. Unlike most gas distribution operators, delivering gas is typically not a master meter operator's primary business.

As a result of the agency's internal review, PHMSA is proposing to exempt master meter operators from DIMP requirements by revising the applicability of subpart P at § 192.1005 and revising § 192.1015. When DIMP was first proposed in 2008 (73 FR 36015), 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 requirements that master meter operators could easily implement and benefit from.

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 inspection and maintenance effort was being used to improve DIMP compliance among master meter operators. Despite these 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 would be better used to effectively implement other basic requirements.

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 proposed DIMP rule 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 management system is not required to integrate data and information in order to identify risk mitigation strategies and actions. PHMSA's experience indicates that the analysis and documentation requirements of DIMP has had little safety benefit for this type of operator. PHMSA, state inspectors and subject matter experts agree that focusing on more fundamental risk mitigation activities (e.g., § 192.605 *Procedural manual for operations, maintenance, and emergencies*, § 192.613 *continuing surveillance*, and § 192.617 *investigations of failures*) has 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. PHMSA believes there are even potential safety benefits to allowing operators and inspectors to instead prioritize the most pertinent compliance activities specific to master meter systems.

Master meter operators would still be subject to the rest of the pipeline safety regulations at part 192, such as the operations and maintenance requirements at subpart L and subpart M, the continuing surveillance requirements at § 192.613 and the failure investigation requirement at § 192.617. PHMSA believes those regulations adequately manage pipeline integrity risks for master meter operators with less burden. In consideration of the proposed DIMP exemption, PHMSA also requests public comment on whether PHMSA should repeal the incident reporting exception for master meter operators (§ 191.9 (c)), including specific safety issues that would merit monitoring through incident reporting requirements for such facilities.

Reporting and Information Collections

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

PHMSA is proposing to remove §§ 191.12 and 192.1009, eliminating the requirement for operators to submit mechanical fitting failure (MFF) reports through DOT Form PHMSA F-7100.1-2. Operators would still be required to submit incident reports, which include almost all of the information on the MFF form, for releases from mechanical fittings that meet the definition of an incident at § 191.3. PHMSA also proposes to revise the gas distribution annual report form (DOT Form PHMSA F 7100.1) to include a count of MFFs. This issue was raised in comments submitted in response to the notice of regulatory reform from the Associations, the Gas Piping Technology Committee (GPTC), and the West Virginia Oil and Natural Gas Association (WVONGA), identifying this reporting requirement as an unnecessary and burdensome information collection.

On February 1, 2011, PHMSA issued the final rule, "Pipeline Safety: Mechanical Fitting Failure Reporting Requirements," (76 FR 5499), adding §§ 191.12, 192.1001, and 192.1009 to the regulations. Section 191.12 sets forth the requirement for operators to report MFFs through DOT Form PHMSA F-7100.1-2. 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 fitting, the vast majority of which are low-consequence events that do not meet the definition of an incident at § 191.3. These changes were initially proposed as a result of investigations of incidents caused by improperly designed or installed mechanical fittings. The intent of collecting this data was to determine the frequency of mechanical fitting failures and identify the most common characteristics of those failures.

Similar to the incident report form, the MFF form[4] requires operators submit information on the design and installation of the failed fitting and the apparent cause of the leak. The form also includes manufacturing information; however, this is commonly not known by the operator. Unlike incident reports, which are required for events that meet the criteria defined in § 191.3, MFF reports are required for each MFF that results in a "hazardous leak", defined at § 192.1001, a much broader category of events. As a result, PHMSA currently collects approximately 15,000 MFF reports each year, compared to approximately 100 gas distribution incidents due to all causes. This has allowed PHMSA to collect and analyze a much larger volume of detailed information regarding MFFs than would be possible from incident reports alone. PHMSA publishes a report on the

[4] PHMSA F-7100.1-2

information collected and its analysis of the information received annually, which is available online.[5]

After over 8 years of collecting and analyzing MFF information, PHMSA has determined that further collection of MFF reports is no longer necessary. PHMSA's past analysis of the MFF data has confirmed the Agency's initial expectations regarding the frequency and characteristics of MFFs when the information collection activity was initiated. Further, PHMSA has not identified any statistically significant trends in the MFF report data over this time period. Finally, improvements in fitting design and operator practices have reduced the risks of these devices on newer installations. PHMSA, therefore, has determined it no longer needs to collect detailed information on thousands of MFFs that do not result in incidents. In the future, a combination of gas distribution incident reports and PHMSA's proposal to add a count of MFFs on gas distribution annual reports will adequately meet PHMSA's information needs with regards to the safety of mechanical fittings.

PHMSA's proposal to replace the requirement to submit a full MFF report with a count of MFFs on the gas distribution annual report[6] results in a net reduction in reporting burden for each event, without a significant loss of useful information to PHMSA. In the future, a combination of incident reports and a count of MFFs on annual reports will continue to provide PHMSA with adequate information regarding the safety of mechanical fittings. If a MFF results in an incident, then the operator must submit a gas distribution incident report form,[7] which currently collects almost all of the data fields on the MFF form.[8] A count of MFF on operators' annual reports allows PHMSA to continue to collect information on

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

[6] DOT Form PHMSA F 7100.1-1 (rev 1/30/2017).

[7] DOT Form PHMSA F 7100.1 (rev 10/2014)).

[8] DOT Form PHMSA F 7100.1-2 (rev 10/2014).

trends in the number of MFFs nationally and compare failure rates among operators, which is useful information for PHMSA and state pipeline safety programs.

PHMSA has determined that requiring a detailed MFF report for each MFF is no longer necessary. PHMSA can meet its information needs with substantially less burden through existing incident reporting requirements and PHMSA's proposal to revise the gas distribution annual report form to include a count of MFFs that result in hazardous leaks. Since PHMSA no longer requires the information on the MFF form for failures that do not lead to incidents, the proposed change eliminates an unnecessary reporting burden and would have no impact on safety.

D. Monetary Threshold for Incident Reporting (Section 191.3)

PHMSA is proposing to revise the definition of an "incident" at § 191.3 to adjust the monetary damage threshold for inflation. PHMSA is proposing to raise the reporting threshold for incidents that result in property damage to $122,000, consistent with inflation since 1984. The property damage criterion includes losses to the operator and others but excludes the cost of lost gas. Any incident that results in one or more of the other criteria (a fatality, an injury that requires in-patient hospitalization, releases over three million cubic feet of gas, or is significant in the judgment of the operator) would still be defined as an incident that must be reported regardless of how much property damage occurs. PHMSA intends to base any finalized version of this provision on the price level at the time of publication of the final rule.

On May 3, 1984, PHMSA's predecessor agency, the Research and Special Programs Administration, added a definition for an "incident" at § 191.3 (49 FR 18960). The definition provides criteria that requires operators to report specific events to PHMSA. The

1984 definition of an incident included, among other things, a release of gas that results in estimated property damage of $50,000 or more. Today, over 30 years later, operators must still submit an incident report for any release that results in estimated property damage of $50,000 or more.

One of the most frequent comments submitted in response to the notice of regulatory reform addressed the $50,000 monetary damage threshold for reporting gas pipeline incidents and hazardous liquid pipeline accidents. The Associations, GPTC, and the GPA Midstream Association[9] submitted comments in response to the notice of regulatory reform that recommended an increase in the monetary damage threshold for reporting gas pipeline incidents and hazardous liquid pipeline accidents. 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.[10] 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.

The proposed revision to the monetary damage threshold brings the incident reporting criteria in-line with the 1984 threshold in inflation-adjusted terms. Based on a review of previous incident reports, adjusting the figure for inflation would decrease the number of events reportable as incidents by approximately one fourth, and reduce those reportable due to only the property-damage criterion by almost half. This rulemaking assumes the threshold set 35 years ago is still appropriate for today once it is adjusted for inflation; however, since the original rulemaking 35 years ago, an improved safety record has decreased the number of significant events, and the safety information needs may have changed. PHMSA seeks

[9] GPA, formerly the Gas Processors Association.
[10] This analysis is based on the CPI for All Urban Consumers (CPI-U) from the Bureau of Labor Statistics, accessed via https://data.bls.gov/cgi-bin/cpicalc.pl.

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 defacto lower threshold after inflation would provide beneficial information on contributing risk factors and incident trends.

PHMSA intends to periodically 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 past 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 uses to update the criteria for reporting accidents/incidents at 49 CFR § 225.19 and Appendix B to part 225. PHMSA seeks comments on the appropriate method and frequency for future updates to the monetary damage threshold.

PHMSA also considered revising the monetary damage threshold by eliminating the monetary damage threshold entirely and only require reporting incidents that meet one of the other criteria. Ultimately, PHMSA chose to propose a monetary damage threshold derived by adjusting the current value for inflation since 1984. This approach aligns with the intent of the 1984 monetary damage threshold and was supported in public comments submitted in response to the notice of regulatory reform. PHMSA determined that eliminating the monetary threshold was not appropriate. Repealing that criterion would eliminate approximately half of all incident reports, significantly reducing the amount of safety data available to PHMSA, state pipeline safety programs, operators, and the public.

Corrosion Control

Virtually all hazardous liquid and most natural gas transmission pipe in service today is made of steel. This steel, when not otherwise protected, reacts with its environment and can deteriorate over time. Under certain conditions, unprotected metal can corrode, causing gas leaks that can threaten public safety. To guard against this, 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 is proposing two amendments related to corrosion control. PHMSA is proposing to clarify that cathodic protection rectifiers can be monitored remotely and to revise the requirements for assessing atmospheric corrosion on distribution service pipelines.

E. External Corrosion Control: Monitoring (Section 192.465)

PHMSA is proposing to revise § 192.465(b), "External corrosion control: Monitoring," to clarify that operators may monitor rectifier stations remotely. As discussed earlier, rectifiers are devices that direct an electrical current on a pipeline to prevent external corrosion. Section 192.465(b) requires regular inspection of rectifiers on gas pipelines 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 is proposing to revise § 192.465(b) to clarify that operators may inspect rectifier stations directly onsite or by way of remote monitoring technologies. This proposed rule also clarifies that, at a minimum, such an inspection consists of recording amperage and voltage measurements. PHMSA is considering a similar revision for monitoring rectifier stations on hazardous liquid pipelines in a separate rulemaking.

Remote monitoring equipment must be properly maintained in order to function safely and as intended. PHMSA's experience has shown that rectifiers, often located in remote areas, can be subject to damage from a variety of sources, including natural forces and vandalism. If an operator chooses to monitor a rectifier remotely, PHMSA proposes to require operators to physically inspect that station whenever they conduct a cathodic protection test pursuant to § 192.465(a). For transmission pipelines and distribution mains, this will occur once each calendar year, concurrent with existing inspection activities required at § 192.465(a).

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

PHMSA is proposing to revise § 192.481 to establish a separate atmospheric corrosion reassessment interval for gas distribution service pipelines. Currently, all onshore gas pipelines that are exposed to the atmosphere must be inspected once every 3 years, not to exceed 39 months. PHMSA proposes a maximum inspection interval for service lines of once every 5 calendar years, not to exceed 63 months, unless atmospheric corrosion was identified on the last inspection. PHMSA also proposes to keep the current inspection interval on service lines with observed corrosion; if an operator identifies atmospheric corrosion on a service line during an inspection, then the interval for the subsequent inspection would be once every 3 years, not to exceed 39 months. If no atmospheric corrosion is identified on a subsequent inspection, then operators would be permitted to revert to the 5-year inspection interval. PHMSA is not aware of any incidents caused by atmospheric corrosion on distribution service lines since at least 1986[11] and does not anticipate a decrease in safety from this change.

Also with regard to atmospheric corrosion, consistent with comments on the notice of regulatory reform, PHMSA proposes to clarify that existing requirements to consider corrosion under DIMP include the consideration of atmospheric corrosion risks. PHMSA would expect 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 this section.

Comments on the notice of regulatory reform from the Associations, APGA, GPTC, and WVONGA recommended that PHMSA revise the atmospheric corrosion inspection requirements for distribution pipelines. The Associations commented that PHMSA should allow operators of distribution pipelines to manage atmospheric corrosion based on the operator's assessment of the risks in accordance with their DIMP plans. Alternatively, APGA recommended simply establishing an inspection interval of 5 years, not to exceed 63 months for all distribution pipelines, which would allow operators to coordinate atmospheric corrosion assessments with leakage surveys (§ 192.723), which also occur at an interval of 5 years, not to exceed 63 months.

[11] 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.

PHMSA considered each of those suggestions as alternatives, and the proposed rule integrates aspects of each. The proposed rule establishes a maximum inspection interval of 5 years for distribution service lines without observed corrosion. PHMSA agreed with the rationale for the benefits of aligning atmospheric corrosion reassessment intervals with those for leakage surveys in § 192.723 presented in comments from APGA. Additionally, 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,[12] and others have been approved in the past in Illinois. PHMSA has not observed an increase in leaks or incidents in these locations, confirming that a longer atmospheric corrosion inspection interval is supported in areas with low atmospheric corrosion risk.

Unlike both other alternatives, which apply to all distribution pipelines, PHMSA limited the revised reassessment interval to distribution service lines. Operators have reported atmospheric corrosion incidents on distribution mains, and compared to mains, service lines tend to be smaller, have lower flow, and are generally built of thicker wall pipe. Additionally, aboveground distribution facilities other than service lines must be inspected frequently under other sections of the PSR, providing ample opportunity 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, rather than an open-ended reference to DIMP, is

[12] Additional information is available in the docket for this action (PHMSA-2019-0052) at https://www.regulations.gov/docket?D=PHMSA-2019-0052.

necessary to ensure that atmospheric corrosion on distribution facilities is being adequately monitored and remediated before it leads to a failure. The proposed maximum interval of five 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 concurrently. Since the primary cost savings comes from coordinating inspection activity, PHMSA was not persuaded that there is significant benefit to allowing atmospheric corrosion inspection intervals longer than the leakage survey interval in § 192.723(b)(2). The proposed requirement to evaluate atmospheric corrosion risks under DIMP and the shorter inspection interval for pipelines with observed corrosion will ensure that operators of service pipelines with atmospheric corrosion threats take appropriate action to maintain the integrity of those pipelines.

The proposed amendments to §§ 192.1007 and 192.1015 clarify that consideration of corrosion under DIMP requires 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 (e.g. humid, coastal environments, or a history of leaks caused by atmospheric corrosion) to take mitigative action, such as more frequent inspection or maintenance activities, as part of their DIMP plans and accurately and completely document such actions.

Standards Incorporated by Reference

G. Plastic Pipe (Sections 192.7, 192.121, Appendix B)

PHMSA is proposing 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).[13] ASTM D2513 is the standard that specifies the design of PE pipe and fittings. After reviewing the standard, PHMSA determined that the improvements since the 2012 edition, which is currently incorporated by reference, justify incorporating by reference the 2018a edition. These improvements include more specific testing requirements for measuring resistance to UV exposure and clarifying the applicability of the document to all fuel gas piping. Consistent with the updated ASTM standard, PHMSA also proposes to raise the diameter limit for using a design factor of 0.4 on PE pipe from 12 inches to 24 inches and add entries for those sizes to the PE minimum wall thickness table at § 192.121(c)(2)(iv). The Plastics Pipe Institute, representing manufacturers of plastic pipe and components, and a citizen commenter submitted comments in response to the notice of regulatory reform addressing this issue. PHMSA reviewed ASTM D2513-18 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.

Currently, PHMSA incorporates by reference ASTM D2513-12ae1 into item I, appendix B to part 192. While Table 2 of ASTM D2513-12ae1 includes outside diameter specifications for pipe sizes up to 24-inch nominal diameter, Table 4 only includes wall

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[13] ASTM D2513-18a, Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings, ASTM International, West Conshohocken, PA, August 1, 2018, www.astm.org.

thickness specifications for pipe sizes up to 12-inch nominal diameter. Since plastic pipe must be manufactured in accordance with a listed specification, it is not clear if and when sizes above 12 inches are allowed. PHMSA's proposal to adopt ASTM D2513-18 and revise the minimum wall thickness table at § 192.121(c)(2)(iv) would resolve this discrepancy.

PHMSA also proposes to clarify and improve requirements for joining procedures in §§ 192.281 and 192.283 to allow operators additional flexibility when developing such procedures and to improve safety. Specifically, PHMSA proposes to incorporate by reference the 2019 edition of ASTM F2620, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings" and make revisions to §§ 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[14] in response to the final rule titled "Pipeline Safety: Plastic Pipe Rule" issued on November 20, 2018 (83 FR 58694).

In the final rule, PHMSA amended §§ 192.281 and 192.285 to require 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 describes 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

[14] See Docket Number PHMSA-2019-0200. https://www.regulations.gov/docket?D=PHMSA-2019-0200.

standard also includes considerations for joining in cold weather and criteria for evaluating the quality of fusion joints.

AGA raised concerns that the language in these sections as written would require operators to requalify safe procedures that were qualified in the past in accordance with § 192.283. AGA specifically mentioned that many operators use heat fusion procedures published by the Plastic Pipe Institute (PPI), a trade association representing manufacturers of plastic pipe and fittings, such as PPI TR-33 and PPI TR-41. While PHMSA noted in the preamble of the final 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 allow the use of other qualified procedures, such as PPI TR-33 and PPI TR-41, under § 192.283.

After reviewing AGA's petition, PHMSA proposes to revise §§ 192.281 and 192.285 consistent with the intent stated in the preamble of the plastic pipe rule. PHMSA proposes 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 internal and external loads, and has 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 final rule, PHMSA expect operators to document the differences from ASTM F2620 and demonstrate how the alternate procedures provide an equivalent or superior level of safety. Similarly, PHMSA proposes 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. PHMSA is not implementing AGA's proposed language to allow any procedure qualified in accordance with §§ 192.281 and 192.285 in order to retain the intended safety benefits of adopting ASTM F2620. If the operator's procedures are found to be lacking in any way—such as changes to surface preparation, heating temperatures, fusion pressures, or cooling times that lack adequate technical justification—they would still be unacceptable.

Related to this issue, PHMSA also proposes to incorporate by reference the 2019 edition of ASTM F2620. The updated edition of the standard clarifies the relationship between ASTM F2620 and the PPI documents referenced in AGA's petition in a new Note 1 in Section 1.2. In addition to clarifying some of AGA's concerns, the 2019 edition of the standard includes a number of incremental improvements to safety and editorial clarity. These improvements include a new section 6.4 that requires additional precautions 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. Additionally, 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 should reduce potential issues caused by inadequate surface preparation, which has been a factor in past incidents.[15]

PHMSA also proposes to clarify § 192.285 in response to questions PHMSA has received following publication of the rule. First, PHMSA proposes to remove references to testing in relation to ASTM F2620 to clarify that only visual inspection in accordance with that standard is required. A number of stakeholders have 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. This change avoids confusion about whether non-mandatory testing described in ASTM F2620 is required. PHMSA also proposes to clarify that testing in accordance with § 192.283(a) is still required for PE heat fusion joints. Especially with the proposed deletion of references to ASTM F2620 testing, the current text could be read to require only visual inspection in accordance with ASTM F2620 for PE heat fusion joints. These changes 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 (or an equivalent or superior procedure).

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

Design Pressure for Plastic Pipe

In § 192.121(a), the words "design formula" are replaced with the words "design pressure," which is more accurate.

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[15] National Transportation Safety Board, "Safety Through Reliable Fusion Joints," SA-047, https://www.ntsb.gov/safety/safety-alerts/Documents/SA_047.pdf, June 2015.

Minimum Wall thickness for 1" CTS Pipe

In the minimum wall thickness tables for polyethylene (§ 192.121(c)(2)(iv)), polyamide 11 (PA-11) (§ 192.121(d)(2)(iv)), and polyamide 12 (PA-12) (§ 192.121(e)(4)), 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, is the correct minimum wall thickness for SDR 11, 1" CTS pipe in ASTM D2513, ASTM F2945, and ASTM F2785.

Qualifying Joining Procedures.

In § 192.283(a)(3), "no more than 25% elongation" is corrected to read "no less than 25% elongation." PHMSA is also proposing to clarify that the test required by this section is a tensile test. The language in the code prior to the plastic pipe rule required tensile testing and the elongation performance metric is a tensile testing metric. However, with other revisions to § 192.283(a)(3) in the plastic rule, the word tensile was inadvertently removed.

Dates

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

Corrections to 192.7

PHMSA also proposes editorial amendments to § 192.7(a) to meet requirements from the Office of the Federal Register and a revision to update the address for API.

H. Test Factors for Pressure Vessels (Section 192.153)

On March 11, 2015, PHMSA published a final rule (80 FR 12762) that, among other changes, added § 192.153(e). Section 192.153(e) clarified that pressure vessels subject to

§ 192.505(b) must be tested to at least the test factor required by that section—1.5 times the maximum allowable operating pressure (MAOP). On April 10, 2015, INGAA submitted a petition for reconsideration concerning the revision, arguing that PHMSA lacked technical justification for a 1.5 times MAOP test factor versus the 1.3 times MAOP test factor permitted in the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME BPVC).

PHMSA commissioned a report by the Oak Ridge National Laboratories on the technical equivalency between the 1992 and 2015 editions of the ASME BPVC. One of the changes between these two editions was the test factor. The 1992 edition of the ASME BPVC has a 1.5 times MAOP test factor, while the 2001 edition and all subsequent editions have a 1.3 times MAOP test factor. That study found that pressure vessels that are designed, fabricated, and tested in accordance with the provisions specified in the 2015 edition of ASME BPVC and are subjected to a hydrostatic test pressure equal to 1.3 MAOP are equivalent in safety to pressure vessels that are designed and fabricated in accordance with the 1992 edition of the standard and subjected to a hydrostatic pressure equal to 1.5 MAOP. A copy of this report is available in the docket.[16]

PHMSA is therefore proposing to revise the test requirements for the pressure vessels described in paragraphs (a) and (b) of § 192.153, "Components fabricated by welding." First, consistent with the 2007 edition of the ASME BPVC,[17] PHMSA is proposing a test factor of 1.3 times the MAOP for pressure vessels installed since July 14, 2004.[18] The test

[16] ORNL/TM-2017/66.
[17] Currently incorporated by reference (*see* § 192.7).
[18] The 2001 edition of the ASME BPVC was the first to allow a 1.3 test factor. PHMSA incorporated by reference that edition into part 192 in June 2004, effective July 14, 2004. All subsequent editions of the ASME BPVC also include a 1.3 test factor. Pressure vessels that were properly designed and tested in accordance with the ASME BPVC since 2004 would be in compliance with the revised PSR, provided they were tested to at least 1.3 times MAOP.

requirements for pressure vessels under the alternative MAOP requirements at § 192.620 remain unchanged. PHMSA is proposing to apply a test pressure factor of 1.3 times MAOP to pressure vessels installed between July 14, 2004, and the effective date of this rule once finalized. Consistent with the revised test pressure factor, PHMSA proposes to exempt pressure vessels installed after July 14, 2004, from the testing requirements at §§ 192.505(b) and 192.619(a)(2) and from the pressure test duration requirements in subpart J. Pressure vessels that were properly designed and tested in accordance with the ASME BPVC since 2004 would be in compliance with the revised PSR, provided they were tested to at least 1.3 times MAOP.

Pressure vessels that are new, replaced, or relocated after the effective date of the rule would need to be tested for the duration required in subpart J for the pipeline to which it is being added. Vessels installed within a pipeline being operated at a hoop stress of 30 percent or more must be tested for either 4 or 8 hours (§ 192.505), vessels installed within a pipeline being operated at a hoop stress less than 30 percent must be tested for at least 1 hour (§ 192.507), and pressure vessels installed within a pipeline being operated at a pressure below 100 psi must be tested for a duration that ensures the discovery of all potentially hazardous leaks (§ 192.509). These are the same, long-standing test duration requirements that currently apply for every other component on a pipeline facility.

For newly manufactured pressure vessels installed after the effective date of the rule, PHMSA proposes to accept pre-installation and manufacturer tests with certain conditions and clarify that the pressure test duration requirements in subpart J apply. PHMSA proposes to accept a pressure test done by the manufacturer in accordance with § 192.153 and the ASME BPVC, provided that the operator conducts and documents an inspection certifying that the pressure vessel has not been damaged during transport. If the pressure vessel has been damaged, it would have to be remediated consistent with the ASME BPVC. A pressure vessel that has been used for any purpose prior to installation on a pipeline facility must be pressure tested again in place, consistent with the existing requirement at § 192.503(a).

Welder Requalification

I. Requalification Scheduling (Section 192.229)

PHMSA is proposing to amend § 192.229(b) to streamline compliance with welder requalification requirements. Currently, welders may not weld with a welding process if they have not engaged in welding with that process within the last six months. GPTC submitted a petition for rulemaking requesting PHMSA allow welders to demonstrate they have engaged in welding with a welding process at least twice each calendar year, but at intervals not exceeding 7 ½ months, provided the welds were tested and found acceptable in accordance with API Standard 1104.[19] API Std 1104 is the primary standard for welding steel piping and for testing welds on steel pipelines. It covers the requirements for welding and nondestructive testing of pipeline welds. In part 192, this standard is used for qualifying welders, welding procedures, and welding operators, and interpreting the results of non-destructive tests. The current requirement does not match other welder requalification requirements that use the flexible calendar year format, and operators must therefore either maintain alternative recordkeeping procedures for this requirement or default to 6 months.

PHMSA is proposing 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 7 ½ months and the welds were tested and

[19] See Docket No. PHMSA-2014-0015.

found acceptable in accordance with API 1104. This change provides operators some flexibility in scheduling welding activities to maintain welder requalification. The proposed revision to § 192.229(b) is also more consistent with § 192.229(d)(2). This is potentially beneficial for welders who weld relatively infrequently. The requirements in § 192.229(b) currently must be completed within the previous 6 months, so a welder who wants to use the same two welds to meet the requirements of both § 192.229(d)(2) and § 192.229(b) currently must perform both welds within 6 months, despite § 192.229(d)(2) allowing for an interval of up to 7 ½ months. The proposed revisions allow such welders to benefit from the flexible language in § 192.229(d)(2). PHMSA does not anticipate a decrease in safety, as a 7 ½-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.

Pre-test Applicability

J. Pre-testing Fabricated Assemblies and Short Segments of Pipe (Section 192.507)

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 greater than 30 percent or more of SMYS if a post-installation test is not practicable. PHMSA is proposing to add a new paragraph (d) to § 192.507 to extend this allowance to steel pipelines operated at a hoop stress less than 30 percent of SMYS and at or above 100 psi.

Section 192.505 outlines strength testing requirements for steel pipelines operating at a hoop stress greater than 30 percent of SMYS. One of the strength testing requirements at § 192.505(d) permits the use of a pre-installation or factory pressure test for fabricated units and short sections of pipe where a post-installation test is not feasible. GPTC petitioned PHMSA to move this provision to the general test requirements in § 192.503. This would permit operators to use pre-tested pipe and fabricated units in applications outside of higher stress transmission pipelines. As this provision is currently applicable to higher-stress pipelines operating at a hoop stress greater than 30 percent of SMYS only, extending the broader pre-testing provision to lower-stress pipelines would not increase pipeline safety risks. This proposed change will provide greater flexibility and efficiency for operators of lower-stress pipelines, especially during maintenance activities.

Typically, a post-installation test is practicable for new construction, but may be impracticable for repairs. For example, to complete a pressure (post-installation) test on a short segment of pipe used as a repair, the area being tested must be isolated from the rest of the line. For a pressure test of a short replacement pipe segment, operators would either weld caps on the segment and test it alongside the pipe in or near the trench, or install the segment and install caps to isolate the segment elsewhere along the line. The former is no different than a "pre-installation" test except that it occurs within the pipeline right of way. The latter requires cutting out additional pipe segments to install the caps necessary to isolate the test segment. Depending on the test procedure, these caps would then be replaced with pre-tested pipe anyway. A pre-installation test in this scenario provides an equivalent or superior level of safety with potentially lower costs.

Instead of adding pre-testing provisions to the general requirements at § 192.503, PHMSA proposes to add § 192.507(d) to permit pre-testing on steel pipelines operating at a hoop stress less than 30 percent of SMYS at or above 100 psi. This does not extend pre-testing provisions to pipelines operating below 100 psi (§ 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 will continue to evaluate this issue and encourages interested parties to submit comments on whether it is appropriate to extend pre-testing provisions to such facilities, propose requirements that should apply if pre-testing provisions are extended to such facilities, and provide any relevant information on safety or cost impacts.

V. 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 60 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. ASTM International (ASTM) often updates some of its more widely used standards every year. Sometimes multiple editions are published in a given year.

The National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104-113, 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, OMB issued Circular A-119 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 has the responsibility 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. 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.

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.

Further, 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 (79 FR 66278).

To meet its statutory obligation 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. The ASTM standards are available at https://www.astm.org/READINGLIBRARY/. In addition, PHMSA will 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

VI. Regulatory Analyses and Notices

A. Legal Authority for this Rulemaking

This proposed rule is published under the authority of the federal pipeline safety statutes (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, section 60102(l) of the federal pipeline safety statutes 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 section 60102 to the Administrator of PHMSA (49 CFR 1.97).

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

E.O. 12866, "Regulatory Planning and Review" (58 FR 51735; Oct. 4, 1993), and DOT regulations governing rulemaking procedures (49 CFR part 5) require that PHMSA submit "significant regulatory actions" to the OMB for review. This NPRM is a significant regulatory action under section 3(f) of E.O. 12866 and under DOT and was therefore reviewed by OMB.

PHMSA anticipates that, if promulgated, this NPRM 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 proposed rule will result in annualized cost savings of approximately $129 million per year, based on a 7 percent discount rate. Nearly all of the quantified cost savings in the proposed rule are from the proposed revisions to farm tap requirements and the revised atmospheric corrosion reassessment interval for distribution service lines. In support of this NPRM, PHMSA prepared a Preliminary RIA with estimated costs and benefits. A copy of the Preliminary RIA is available in the public docket.

C. Executive Order 13771

This proposed rule is expected to be an EO 13771 deregulatory action. Details on the estimated cost savings of this proposed rule can be found in the rule's economic analysis in the RIA.

D. Executive Order 13132 - "Federalism"

E.O. 13132 (64 FR 43255; Aug. 10, 1999) imposes certain requirements on federal agencies formulating or implementing policies or regulations that preempt state law or that have federalism implications. This NPRM 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 NPRM also does not impose substantial direct compliance costs on state and local governments.

The proposed rule could have preemptive effect because the pipeline safety laws, specifically 49 U.S.C. 60104(c), prohibit state safety regulation of interstate pipelines. Under the pipeline safety law, states have the ability to 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 proposed rule is limited to the minimum level necessary to achieve the objectives of the pipeline safety laws under which the proposed 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"

E.O. 13175 (65 FR 67249; Nov. 6, 2000) requires agencies to consider and consult with Tribal governments when formulating policies. PHMSA does not anticipate that this NPRM will significantly or uniquely affect Tribal governments or impose substantial direct compliance costs; as such, the funding and consultation requirements of E.O 13175 would not apply. PHMSA invites Tribal communities and governments to comment on this NPRM.

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

E.O. 13211 (66 FR 28355; May 22, 2001) requires agencies to submit "significant energy actions" to OMB for review. This NPRM is not a "significant energy action" under E.O.13211 because it is unlikely to have a significant adverse effect on the supply, distribution, or use of energy. Therefore, no additional analysis is necessary under E.O. 13211.

G. Executive Order 13272 - "Regulatory Flexibility Act"

The Regulatory Flexibility Act of 1980 (5 U.S.C. 601 *et seq.*), as amended, requires federal agencies to prepare an initial regulatory flexibility analysis describing impacts on small entities whenever an agency is required by 5 U.S.C. 553 to publish a general notice of proposed rulemaking for any proposed rulemaking. PHMSA determined that the cost-savings in the proposed rule may result in significant economic impacts on a substantial number of small entities. An analysis of the potential economic impacts of the proposed rule on small entities is included in the RIA, which is available for public review and comment 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. PHMSA estimates that the proposals in this rulemaking will impact the information collections described below.

Based on the proposals in this rule, PHMSA will submit an information collection revision request to OMB for approval based on the requirements in this proposed rule. 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 and Annual 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 26 fewer gas distribution incident reports, and 13 fewer gas transmission reports. Operators currently spend 12 hours completing each incident report. Therefore, PHMSA expects to eliminate 39 responses and

468 hours from this information collection 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: 262.

Total Annual Burden Hours: 3,144.

Frequency of Collection: On Occasion.

2. Title: Incident and Annual 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 Mechanical Fitting Failure 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. PHMSA estimates that it currently receives, on average, 8,300 Mechanical Fitting Failure 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 Federal Pipeline Safety Regulations require operators of gas distribution pipelines to develop and implement IM programs.

PHMSA proposes to eliminate this requirement for master meter operators. 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 for 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 Federal Pipeline Safety Regulations require distribution operators to prepare and submit annual reports with summary information on their pipeline infrastructure. PHMSA proposes to shift the mechanical fitting failure form requirements to a count of mechanical fitting failures on the distribution annual report form. PHMSA estimates that it will take operators approximately 25 minutes (.42 hours) to add this information to the annual report. As a result, the burden for this information collection will increase by approximately 607 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: 25,189.

Frequency of Collection: Annually.

I. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1501 *et seq.*) requires federal agencies to assess the effects of federal regulatory actions on state, local, and tribal governments, and the private sector.[20] For any NPRM 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 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.[21] A federal mandate is defined, in part, as a regulation that imposes an

[20] 2 U.S.C. 1531.
[21] *Id.* 1532.

enforceable duty upon state, local, or Tribal governments or would reduce or eliminate the amount of authorization of appropriation for federal financial assistance that would be provided to state, local, or Tribal governments for the purpose of complying with a previous federal mandate.[22] This NPRM imposes no unfunded mandates. If promulgated, this rule would not result in costs of $100 million, adjusted for inflation, or more in any one year to either state, local, or Tribal governments, in the aggregate, or to the private sector.

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 NPRM in accordance with NEPA, NEPA implementing regulations (40 CFR parts 1500-1508), and DOT Order 5610.1C. PHMSA has prepared a preliminary environmental assessment (EA) and determined this action will not significantly affect the quality of the human environment. A copy of the EA for this action is available in the docket. PHMSA invites comment on the environmental impacts of this proposed rulemaking.

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

Part 191

[22] *Id.* §§ 658(5)(A), 1555.

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

Part 192

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

For the reasons provided in the preamble, PHMSA is proposing to amend 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: 49 U.S.C. 5121, 60102, 60103, 60104, 60108, 60117, 60118, 60124, 60132, and 60141; 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; or

* * * * *

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 an unregulated gathering or production pipeline.

§ 191.12 [Removed and reserved].

4. Remove and reserve § 191.12.

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: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, 60137, and 60141; 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 paragraphs (d)(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. 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, Web site: *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); 192.229(c); 192.241(c); and Item II, Appendix B.

*   *   *   *   *

(d)   *   *   *

(13) 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," Feb. 1, 2019, (ASTM F2620), IBR approved for §§192.281(c) and 192.285(b)(2)(i).

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), (c)(2)(iv), and (d)(2)(iv);

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

5) Revise paragraph (e)(4).

The revisions read as follows:

§ 192.121 Design of plastic pipe.

(a) *Design pressure.* The design pressure for plastic pipe is * * *

* * * * *

(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	0.101	11

1” IPS	0.119	11
1 ¼” IPS	0.151	11
1 ½” 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	0.101	11
1” IPS	0.119	11
1 ¼ IPS	0.151	11
1 ½” 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	0.101	11
1” IPS	0.119	11
1 ¼” IPS	0.151	11
1 ½” 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 paragraph (b) introductory text 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:

*   *   *   *   *

(e) The test requirements for pressure vessels, 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) Pressure vessels installed after July 14, 2004 are not subject to the strength testing requirements at §§ 192.505(b) and 192.619(a)(2), but must be pressure 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) Pressure vessels must be pressure tested for a duration specified as follows:

(i) Pressure vessels installed after July 14, 2004, but before [Insert the Effective Date of the Rule] are exempt from §§ 192.505(c), 192.505(d), and 192.507(c) and must instead be tested for a duration consistent with the ASME BPVC requirements referenced in paragraph (a) or (b) of this section.

(ii) Pressure vessels installed on or after [EFFECTIVE DATE OF FINAL RULE] must be tested for the duration specified in either § 192.505(c), 192.505(d), 192.507(c), or 192.509(a), whichever is applicable for the pipeline in which the component is being installed.

(3) After [EFFECTIVE DATE OF FINAL RULE], if a newly manufactured pressure vessel is relocated to a pipeline facility after an initial pressure test by the manufacturer, the operator must either:

(i) Pressure test the vessel in-place after it has been transported in accordance with the requirements of this section; or

(ii) Inspect the pressure vessel and confirm that the component was not damaged during transportation and installation into the pipeline. Inspection records for the component must be kept for the operational life of the pressure vessel. If the pressure vessel has been damaged, it must be remediated or retested in accordance with the ASME BPVC requirements referenced in paragraphs (a) or (b) of this section.

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 7 ½ 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 equivalent or superior written procedure that 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)(2)(i) to read as follows

§ 192.285 Plastic pipe: Qualifying persons to make joints

* * * * *

(b) * * *

(2) * * *

(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;

* * * * *

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 2 ½ 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) Each remotely monitored rectifier must be physically inspected for continued safe and reliable operation whenever cathodic protection tests are performed pursuant to § 192.465(a).

* * * * *

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, with an interval not exceeding 39 months.

15. 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 maintaining the pressure at or above the test pressure for at least 8 hours.

* * * * *

16 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.

17. In section 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 that is not operated as part of a distribution system.

*   *   *   *   *

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

(1) Service lines that only serve engines that power irrigation pumps;

(2) Service lines included in a distribution integrity management plan meeting the requirements of subpart P of this part;

(3) Service lines directly connected to unregulated gathering or production pipelines; and

(4) Pipe segments upstream of either: the inlet to the first pressure regulator, the connection to customer-owned piping, or the outlet of the meter, whichever is further upstream.

18. Revise section 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 or unregulated gathering pipeline;

(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.

19. 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?

* * * * *

20. 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]

21. Remove and reserve § 192.1009.

22. In § 192.1015, revise the section heading, paragraph (a), and paragraph (b)(2) 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) * * *

(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.

*   *   *   *   *

23. In § 192, in Appendix B, remove the entry for ASTM D2513-12ae1 and add a new entry for ASTM D2513 in alphabetical order to read as follows:

Appendix B to Part 192—Qualification of Pipe

I. Listed Pipe Specifications

*   *   *   *   *

ASTM D2513—Polyethylene thermoplastic pipe and tubing, “Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings,” (incorporated by reference, *see* § 192.7).

***   *   *   *   ***

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