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Public Service Commission

May 25, 2019

Jamie L. Jackson, Senior Attorney
Joint Administrative Procedures Committee
Room 680, Pepper Building
111 W. Madison Street
Tallahassee, FL 32399-1400

RE: Docket No. 20190047-GU, Rule 25-12.005, F.A.C., Codes and Standards Adopted

Dear Ms. Jackson:

This letter responds to your letter of April 26, 2019, wherein you offered comment regarding Rule 25-12.005, F.A.C. In the rule, the Commission is updating the reference materials to incorporate the updated version of the 49 of the Code of Regulations. You stated that the referenced materials in the rule, the electronic version of the federal Code of Regulations (eCFRs), should be revised. You stated that the rule's reference materials should reflect the officially codified versions of 49 of the Code of Regulations instead of the eCFRs. You also stated that if amendments to certain regulations have been subsequently changed since the last official codified version, that these amendments may be incorporated in the rule with a copy of the Federal Register. Additionally, you asked us to provide updated copies of the materials that will be incorporated by reference in the rule.

In response to your comments, the Commission will publish a Notice of Change in the Florida Administrative Register to reflect the changes made to the rule, as set forth in the attached copy of the rule. In addition, I have attached the updated copies of the materials that will be incorporated by reference into the rule as you requested. If you have any further questions or comments, please contact me at (850) 413-6082 or aharper@psc.state.fl.us. Thank you for your assistance.

Sincerely,

Adria E. Harper
Senior Attorney

cc: Office of Commission Clerk

25-12.005 Codes and Standards Adopted.

The ~~Minimum Federal Safety Standards and~~ reporting requirements for pipeline facilities and transportation of gas prescribed by the Pipeline and Hazardous Materials Safety Administration in 49 C.F.R. 191 (October 1, 2018) ~~and 192 (2019)~~, is ~~are~~ adopted and incorporated by reference as part of these rules~~.~~ ~~49 C.F.R. 191 (2019)~~ and may be accessed at [insert hyperlink]. The Minimum Federal Safety Standards for pipeline facilities and transportation of gas prescribed by the Pipeline and Hazardous Materials Safety Administration 49 C.F.R. Sections 192.121, 192.123, 192.143, 192.145, 192.149, 192.191, 192.204, 192.281, 192.283, 192.285, 192.3, 192.313, 192.321, 192.329, 192.367, 192.375, 192.376, 192.455, 192.513, 192.59, 192.720, 192.756, of 49 C.F.R. 192, as amended by 83 Federal Register 58716, November 20, 2018, are adopted and incorporated by reference as part of these rules and ~~49 C.F.R. 192 (2019)~~ may be accessed at [insert hyperlink]. The remaining sections of 49 C.F.R. 192, as of October 1, 2018, are adopted and incorporated by reference as part of these rules and may be accessed at [insert hyperlink]. 49 C.F.R. 199 (October 1, 2018) ~~(2019)~~, "Drug and Alcohol Testing," is adopted and incorporated by reference as part of these rules to control drug use, by setting standards and requirements to apply to the testing and use of all emergency response personnel under the direct authority or control of a gas utility or pipeline operator, as well as all employees directly or indirectly employed by gas pipeline operators for the purpose of operation and maintenance and all employees directly or indirectly employed by intrastate gas distribution utilities for onsite construction of natural gas transporting pipeline facilities. 49 C.F.R. 199 (October 1, 2018) ~~(2019)~~ may be accessed at [insert hyperlink]. Part 199 also is adopted to prescribe standards for use of employees who do not meet the requirements of the regulations.

Rulemaking Authority 368.03, 368.05(2), 350.127(2) FS. Law Implemented 368.03, 368.05 FS. History–New 11-14-70, Amended 9-24-71, 9-21-74, 10-7-75, 11-30-82, 10-2-84, Formerly

CODING: Words underlined are additions; words in struck through type are deletions from existing law.

25-12.05, Amended 8-8-89, 1-7-92, 5-13-99, 4-26-01, 12-15-09, 10-11-12, 3-2-17, ________

CODING: Words underlined are additions; words in ~~struck through~~ type are deletions from existing law.

§ 190.411 Procedures for billing and payment of fee.

All PHMSA cost calculations for billing purposes are determined from the best available PHMSA records.

(a) PHMSA bills an applicant for cost recovery fees as specified in the Master Agreement, but the applicant will not be billed more frequently than quarterly.

(1) PHMSA will itemize cost recovery bills in sufficient detail to allow independent verification of calculations.

(2) [Reserved]

(b) PHMSA will monitor the applicant's account balance. Should the account balance fall below the required minimum balance specified in the Master Agreement, PHMSA may request at any time the applicant submit payment within 30 days to maintain the minimum balance.

(c) PHMSA will provide an updated estimate of costs to the applicant on or near October 1st of each calendar year.

(d) Payment of cost recovery fees is due within 30 days of issuance of a bill for the fees. If payment is not made within 30 days, PHMSA may charge an annual rate of interest (as set by the Department of Treasury's Statutory Debt Collection Authorities) on any outstanding debt, as specified in the Master Agreement.

(e) Payment of the cost recovery fee by the applicant does not obligate or prevent PHMSA from taking any particular action during safety inspections on the project.

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

Sec.

AUTHORITY: 49 U.S.C. 5121, 60102, 60103, 60104, 60108, 60117, 60118, 60124, 60132, and 60141; and 49 CFR 1.97.

§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-related conditions, annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of underground natural gas storage facilities and natural gas pipeline facilities located in the United States or Puerto Rico, including underground natural gas storage facilities and pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to—

(1) Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design,

construction, operation, and maintenance under 49 CFR 190.9.

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator; or

(4) Onshore gathering of gas—

(i) Through a pipeline that operates at less than 0 psig (0 kPa);

(ii) Through a pipeline that is not a regulated onshore gathering line (as determined in § 192.8 of this subchapter); and

(iii) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612.

[Amdt. 191–5, 49 FR 18960, May 3, 1984, as amended by Amdt. 191–6, 53 FR 24949, July 1, 1988; Amdt. 191–11, 61 FR 27793, June 3, 1996; Amdt. 191–12, 62 FR 61695, Nov. 19, 1997; Amdt. 191–15, 68 FR 46111, Aug. 5, 2003; 70 FR 11139, Mar. 8, 2005; 75 FR 72904, Nov. 26, 2010; Amdt. 191–24, 81 FR 91871, Dec. 19, 2016]

§ 191.3 Definitions.

As used in this part and the PHMSA Forms referenced in this part—

Administrator means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate

Confirmed Discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.

Gas means natural gas, flammable gas, or gas which is toxic or corrosive;

Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility, liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

(i) A death, or personal injury necessitating in-patient hospitalization;

(ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost; or

(iii) Unintentional estimated gas loss of three million cubic feet or more.

(2) An event that results in an emergency shutdown of an LNG facility or an underground natural gas storage facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.

(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

LNG facility means a liquefied natural gas facility as defined in § 193.2007 of part 193 of this chapter;

Master Meter System means a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as by rents;

Municipality means a city, county, or any other political subdivision of a State;

Offshore means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters;

Operator means a person who engages in the transportation of gas;

Outer Continental Shelf means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof;

Pipeline or *Pipeline System* means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

State includes each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico;

Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas in or affecting interstate or foreign commerce.

Underground natural gas storage facility means an underground natural gas storage facility as defined in § 192.3 of this chapter.

[35 FR 320, Jan. 8, 1970, as amended by Amdt. 191–5, 49 FR 18960, May 3, 1984; Amdt. 191–10, 61 FR 18516, Apr. 26, 1996; Amdt. 191–12, 62 FR 61695, Nov. 19, 1997; 68 FR 11749, Mar. 12, 2003; 70 FR 11139, Mar. 8, 2005; 75 FR 72905, Nov. 26, 2010; Amdt. 191–24, 81 FR 91871, Dec. 19, 2016; Amdt. 191–25, 82 FR 7997, Jan. 23, 2017]

§ 191.5 Immediate notice of certain incidents.

(a) At the earliest practicable moment following discovery, but no later than one hour after confirmed discovery, each operator must give notice in accordance with paragraph (b) of this section of each incident as defined in § 191.3.

(b) Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800–424–8802 (in Washington, DC, 202 267–2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

(1) Names of operator and person making report and their telephone numbers.

(2) The location of the incident.

(3) The time of the incident.

(4) The number of fatalities and personal injuries, if any.

(5) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

(c) Within 48 hours after the confirmed discovery of an incident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in paragraph (b) of this section with an estimate of the amount of product released, an estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.

[Amdt. 191–4, 47 FR 32720, July 29, 1982, as amended by Amdt. 191–5, 49 FR 18960, May 3, 1984; Amdt. 191–8, 54 FR 40878, Oct. 4, 1989; 75 FR 72905, Nov. 26, 2010; Amdt. 191–25, 82 FR 7997, Jan. 23, 2017]

§ 191.7 Report submission requirements.

(a) *General.* Except as provided in paragraphs (b) and (e) of this section, an operator must submit each report required by this part electronically to the Pipeline and Hazardous Materials Safety Administration at *http://portal.phmsa.dot.gov/pipeline* unless an alternative reporting method is authorized in accordance with paragraph (d) of this section.

(b) *Exceptions:* An operator is not required to submit a safety-related condition report (§ 191.25) electronically.

(c) *Safety-related conditions.* An operator must submit concurrently to the applicable State agency a safety-related condition report required by § 191.23 for intrastate pipeline transportation or when the State agency acts as an agent of the Secretary with respect to interstate transmission facilities.

(d) *Alternative Reporting Method.* If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP–20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202–366–8075, or electronically to *informationresourcesmanager@dot.gov* or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

(e) *National Pipeline Mapping System (NPMS)*. An operator must provide the NPMS data to the address identified in the NPMS Operator Standards manual available at *www.npms.phmsa.dot.gov* or by contacting the PHMSA Geographic Information Systems Manager at (202) 366–4595.

[75 FR 72905, Nov. 26, 2010, as amended at by Amdt. 191-23, 80 FR 12777, Mar. 11, 2015]

§ 191.9 Distribution system: Incident report.

(a) Except as provided in paragraph (c) of this section, each operator of a distribution pipeline system shall submit Department of Transportation Form RSPA F 7100.1 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5.

(b) When additional relevant information is obtained after the report is submitted under paragraph (a) of this section, the operator shall make supplementary reports as deemed necessary with a clear reference by date and subject to the original report.

(c) Master meter operators are not required to submit an incident report as required by this section.

[Amdt. 191-5, 49 FR 18960, May 3, 1984, as amended at 75 FR 72905, Nov. 26, 2010]

§ 191.11 Distribution system: Annual report.

(a) *General*. Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.1–1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(b) *Not required*. The annual report requirement in this section does not apply to a master meter system or to a petroleum gas system that serves fewer than 100 customers from a single source.

[75 FR 72905, Nov. 26, 2010]

§ 191.12 Distribution Systems: Mechanical Fitting Failure Reports

Each mechanical fitting failure, as required by § 192.1009, must be submitted on a Mechanical Fitting Failure Report Form PHMSA F–7100.1–2. An operator must submit a mechanical fitting failure report for each mechanical fitting failure that occurs within a calendar year not later than March 15 of the following year (for example, all mechanical failure reports for calendar year 2011 must be submitted no later than March 15, 2012). Alternatively, an operator may elect to submit its reports throughout the year. In addition, an operator must also report this information to the State pipeline safety authority if a State has obtained regulatory authority over the operator's pipeline.

[76 FR 5499, Feb. 1, 2011]

§ 191.13 Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines.

Each operator, primarily engaged in gas distribution, who also operates gas transmission or gathering pipelines shall submit separate reports for these pipelines as required by §§ 191.15 and 191.17. Each operator, primarily engaged in gas transmission or gathering, who also operates gas distribution pipelines shall submit separate reports for these pipelines as required by §§ 191.9 and 191.11.

[Amdt. 191-5, 49 FR 18961, May 3, 1984]

§ 191.15 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.

(a) *Transmission or Gathering*. Each operator of a transmission or a gathering pipeline system must submit DOT Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 of this part.

(b) *LNG*. Each operator of a liquefied natural gas plant or facility must submit DOT Form PHMSA F 7100.3 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 of this part.

(c) *Underground natural gas storage facility.* Each operator of an underground natural gas storage facility must submit DOT Form PHMSA F7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5.

(d) *Supplemental report.* Where additional related information is obtained after a report is submitted under paragraph (a), (b) or (c) of this section, the operator must make a supplemental report as soon as practicable with a clear reference by date to the original report.

[75 FR 72905, Nov. 26, 2010; as amended by Amdt. 191-24, 81 FR 91871, Dec. 19, 2016]

§ 191.17 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Annual report.

(a) *Transmission or Gathering.* Each operator of a transmission or a gathering pipeline system must submit an annual report for that system on DOT Form PHMSA 7100.2.1. This report must be submitted each year, not later than March 15, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

(b) *LNG.* Each operator of a liquefied natural gas facility must submit an annual report for that system on DOT Form PHMSA 7100.3–1 This report must be submitted each year, not later than March 15, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

(c) *Underground natural gas storage facility.* Each operator of an underground natural gas storage facility must submit an annual report on DOT PHMSA Form 7100.4–1 by March 15, for the preceding calendar year except that the first report must be submitted by July 18, 2017.

[75 FR 72905, Nov. 26, 2010, as amended by Amdt. 191-24, 81 FR 91871, Dec. 19, 2016]

§ 191.21 OMB control number assigned to information collection.

This section displays the control number assigned by the Office of Management and Budget (OMB) to the information collection requirements in this part. The Paperwork Reduction Act requires agencies to display a current control number assigned by the Director of OMB for each agency information collection requirement.

OMB CONTROL NUMBER 2137–0522

Section of 49 CFR part 191 where identified	Form No.
191.5	Telephonic.
191.9	PHMSA 7100.1, PHMSA 7100.3.
191.11	PHMSA 7100.1–1, PHMSA 7100.3–1.
191.12	PHMSA 7100.1–2.
191.15	PHMSA 7100.2, PHMSA 7100.3.
191.17	PHMSA 7100.2–1, PHMSA 7100.3–1.PHMSA 7100.4–1.
191.22	PHMSA 1000.1, PHMSA 1000.2.

[75 FR 72905, Nov. 26, 2010, as amended by Amdt. 191-24, 81 FR 91871, Dec. 19, 2016]

§ 191.22 National Registry of Pipeline and LNG operators.

(a) *OPID request.* Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, underground natural gas storage facility, LNG plant or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline, Underground Natural Gas Storage Facility, and LNG Operators in accordance with § 191.7.

(b) *OPID validation.* An operator who has already been assigned one or more OPID by January 1, 2011, must validate the information associated with each OPID through the National Registry of Pipeline, Underground Natural Gas Storage Facility, and LNG Operators at *http://opsweb.phmsa.dot.gov*, and correct that information as necessary, no later than June 30, 2012.

(c) *Changes.* Each operator of a gas pipeline, gas pipeline facility, underground natural gas storage facility, LNG plant, or LNG facility must notify PHMSA electronically through the National Registry of Pipeline, Underground Natural Gas Storage Facility, and LNG Operators at *http://opsweb.phmsa.dot.gov* of certain events.

(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

(i) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

(ii) Construction of 10 or more miles of a new or replacement pipeline;

(iii) Construction of a new LNG plant or LNG facility; or

(iv) Construction of a new underground natural gas storage facility or the abandonment, drilling or well workover (including replacement of wellhead, tubing, or a new casing) of an injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility.

(v) Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or

(vi) A pipeline converted for service under § 192.14 of this chapter, or a change in commodity as reported on the annual report as required by § 191.17.

(2) An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

(i) A change in the primary entity responsible (*i.e.*, with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.

(ii) A change in the name of the operator;

(iii) A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, underground natural gas storage facility, or LNG facility;

(iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter;

(v) The acquisition or divestiture of an existing LNG plant or LNG facility subject to Part 193 of this subchapter; or

(vi) The acquisition or divestiture of an existing underground natural gas storage facility subject to part 192 of this subchapter.

(d) *Reporting.* An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.

[Amdt. 191-21, 75 FR 72906, Nov. 26, 2010, as amended by Amdt. 191-24, 81 FR 91871, Dec. 19, 2016; Amdt. 191-25, 82 FR 7997, Jan. 23, 2017]

§ 191.23 Reporting safety-related conditions.

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with § 191.25 the existence of any of the following safety-related conditions involving facilities in service:

(1) In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) In the case of an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well, general corrosion that has reduced the wall thickness to less than that required for the maximum well operating pressure, and localized corrosion pitting to a degree where leakage might result.

(3) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of an underground natural

gas storage facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility, or LNG facility that contains, controls, or processes gas or LNG.

(4) Any crack or other material defect that impairs the structural integrity or reliability of an underground natural gas storage facility or LNG facility that contains, controls, or processes gas or LNG.

(5) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20% or more of its specified minimum yield strength or underground natural gas storage facility, including injection, withdrawal, monitoring, or observations well for an underground natural gas storage facility.

(6) Any malfunction or operating error that causes the pressure of a pipeline or underground natural gas storage facility or LNG facility that contains or processes gas or LNG to rise above its maximum well operating pressure (or working pressure for LNG facilities) plus the margin (build-up) allowed for operation of pressure limiting or control devices.

(7) A leak in a pipeline or an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility, or LNG facility that contains or processes gas or LNG that constitutes an emergency.

(8) Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.

(9) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of a pipeline or an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility, or an LNG facility that contains or processes gas or LNG.

(b) A report is not required for any safety-related condition that—

(1) Exists on a master meter system or a customer-owned service line;

(2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;

(3) Exists on a pipeline (other than an LNG facility or Underground Natural Gas Storage facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

[Amdt. 191–6, 53 FR 24949, July 1, 1988, as amended by Amdt. 191–14, 63 FR 37501, July 13, 1998; Amdt. 191–24, 81 FR 91872, Dec. 19, 2016]

§ 191.25 Filing safety-related condition reports.

(a) Each report of a safety-related condition under § 191.23(a) must be filed (received by OPS within five working days, not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by electronic mail to *InformationResourcesManager@dot.gov* or by facsimile at (202) 366–7128.

(b) The report must be headed "Safety-Related Condition Report" and provide the following information:

(1) Name and principal address of operator.

(2) Date of report.

(3) Name, job title, and business telephone number of person submitting the report.

(4) Name, job title, and business telephone number of person who determined that the condition exists.

(5) Date condition was discovered and date condition was first determined to exist.

(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.

(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.

(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

[Amdt. 191–6, 53 FR 24949, July 1, 1988; 53 FR 29800, Aug. 8, 1988, as amended by Amdt. 191–7, 54 FR 32344, Aug. 7, 1989; Amdt. 191–8, 54 FR 40878, Oct. 4, 1989; Amdt. 191–10, 61 FR 18516, Apr. 26, 1996; Amdt. 191–23, 80 FR 12777, Mar. 11, 2015]

§ 191.29 National Pipeline Mapping System.

(a) Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:

(1) Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at *www.npms.phmsa.dot.gov* or by contacting the PHMSA Geographic Information Systems Manager at (202) 366–4595.

(2) The name of and address for the operator.

(3) The name and contact information of a pipeline company employee, to be displayed on a public Web site, who will serve as a contact for questions from the general public about the operator's NPMS data.

(b) The information required in paragraph (a) of this section must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available at *www.npms.phmsa.dot.gov* or contact the PHMSA Geographic Information Systems Manager at (202) 366–4595.

[Amdt. 191–23, 80 FR 12777, Mar. 11, 2015]

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

Subpart A—General

Subpart B—Materials

Subpart C—Pipe Design

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA-2014-0098: Amdt. No. 192-124]

RIN 2137-AE93

Pipeline Safety: Plastic Pipe Rule

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

ACTION: Final rule.

SUMMARY: PHMSA is amending the Federal Pipeline Safety Regulations that govern the use of plastic piping systems in the transportation of natural and other gas. These amendments are necessary to enhance pipeline safety, adopt innovative technologies and best practices, and respond to petitions from stakeholders. The changes include increasing the design factor of polyethylene pipe; increasing the maximum pressure and diameter for Polyamide-11 pipe and components; allowing the use of Polyamide-12 pipe and components; new standards for risers, more stringent standards for plastic fittings and joints; stronger mechanical fitting requirements; the incorporation by reference of certain new or updated consensus standards for pipe, fittings, and other components; the qualification of procedures and personnel for joining plastic pipe; the installation of plastic pipe; and a number of general provisions.

DATES: The effective date of these amendments is January 22, 2019. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of January 22, 2019.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of Regulatory Action

PHMSA is amending the Federal Pipeline Safety Regulations that govern the use of plastic piping systems in the transportation of natural and other gas. This final rule is comprised of amendments that will improve safety, allow for expanded use of plastic pipe products, and allow or require the use of certain materials and practices. The use and availability of plastic pipe have changed over the years with technological innovations in the products and best practices used in plastic pipe installations. Progress in the design and manufacture of plastic pipe and components has resulted in materials with higher strength characteristics. Manufacturers are instituting new practices related to traceability, and operators are incorporating these practices. Together, these measures have the potential to improve pipeline safety and integrity. The pipeline safety regulations have not stayed current with some of these developments. Many of PHMSA's stakeholders have petitioned PHMSA to codify measures from the progress the industry has made; these petitions are detailed below. This final rule amends the Federal Pipeline Safety Regulations (PSR) to incorporate these changes to enhance pipeline safety, respond to petitions for rulemaking, and accommodate innovations in plastic pipe materials and designs.

PHMSA received several petitions for rulemaking under 49 CFR 190.331 regarding plastic pipe. Copies of these petitions are available in the docket for this rulemaking (PHMSA-2014-0098) in addition to the dockets initially established for the petitions. The amendments in this rulemaking will address the following petitions:

- American Gas Association (AGA)—(Docket No. PHMSA 2010-0011)—Petition to increase design factor of PE pipe 0.32 to 0.4 and incorporate updated ASTM International (ASTM) D2513 (standard for polyethylene (PE) pipe and fittings).
- Evonik Industries (Evonik) and UBE Industries (UBE)—(Docket No. PHMSA 2010-0009)—Petition to allow use of Polyamide-12 (PA-12) pipe.
- Arkema—(Docket No. PHMSA 2013-0227)—Petition to allow use of Polyamide-11 (PA-11) pipe at higher pressures.
- Gas Piping Technology Committee (GPTC)—Petition to allow above-ground, encased plastic pipe for regulator and metering stations.

Federal and State inspectors have noticed issues related to plastic pipe installation that should be addressed in the pipeline safety regulations. For example, the National Association of Pipeline Safety Representatives (NAPSR), an association of State pipeline safety regulators, petitioned PHMSA to establish permanency requirements for pipe markings in Resolution SR 2-01. Approved on September 27, 2001, Resolution SR2-01 encouraged PHMSA OPS to amend 49 CFR 192.63 "to require marking of all pipe, fittings, and components in such a manner that the markings last for a period of 50 years or the life of the pipe, fittings, and components."

B. Summary of Regulatory Provisions

To address these issues and petitions, PHMSA is amending the PSR in 49 CFR part 192 to update the plastic pipe regulations. This rulemaking limits these changes to new, repaired, and replaced pipelines. The changes include increasing the design factor of PE pipe; increasing the maximum pressure and diameter for PA-11 pipe and components; allowing the use of PA-12 pipe and components; new standards for risers; more stringent standards for plastic fittings and joints; stronger mechanical fitting requirements; new and expanded standards for the installation of plastic pipe; the incorporation by reference of certain the qualification of procedures and personnel for joining plastic pipe; the installation of plastic pipe; new or updated consensus standards for pipe, fittings, and other components; the qualification of procedures and personnel for joining plastic pipe; the installation of plastic pipe; and a number of general provisions. These amendments are described in Part III of this document and in further detail in the Notice of Proposed Rulemaking (NPRM) published May 21, 2015. *See* 80 FR 29263.

C. Costs and Benefits

In accordance with 49 U.S.C. 60102, Executive Orders 12866 and 13563, and U.S. DOT policy, PHMSA has prepared an assessment of the benefits and costs of the rule as well as reasonable alternatives. PHMSA released the initial Regulatory Impact Analysis (RIA) concurrent with the NPRM for public review and comment. PHMSA developed the final RIA by incorporating further internal review and input from public comments. PHMSA has published the final RIA concurrent with this final rule, and it is available in the docket. PHMSA quantified positive net benefits of $32.7 million, mostly from cost savings due to the change in the PE design factor. Other changes enhance pipeline safety, expand flexibility in pipe material choice, and incorporate more modern technical consensus standards.

PHMSA quantified approximately $391,000 in annualized safety benefits from the revisions to plastic pipe installation requirements. This estimate is based on the historical frequency and consequences of incidents on plastic pipe systems that could have been prevented by the changes in the final rule. PHMSA also determined unquantified safety benefits from enhanced standards for fittings and risers, prohibiting the permanent use of temporary leak repair clamps, and other general provisions. PHMSA estimated that the revised design factor for PE, relaxed restrictions on PA–11, incorporation of PA–12, and updated standards for all three materials would have negligible impacts on pipeline safety. Overall, the rule improves the safety of plastic pipe systems.

On the cost side, PHMSA quantified $32 million in cost savings for the revision to the design factor of PE pipe from 0.32 to 0.40. The change in design factor leads to pipe material cost savings as it permits pipe to operate at higher pressures for a given pipe size and wall thickness. PHMSA also determined that the provisions for expanded use of PA–11 and incorporation of PA–12 materials would lead to unquantified cost savings to operators from greater flexibility in pipeline material choice. The other provisions have unquantified costs, however PHMSA expects these to be minimal as they generally incorporate existing industry best practices by incorporating by reference technical consensus standards.

II. Background

A. Notice of Proposed Rulemaking

On May 21, 2015, PHMSA published the Plastic Pipe NPRM and requested feedback and public comments on the proposed changes to the natural gas pipeline safety regulations in accordance with the Administrative Procedure Act, 5 U.S.C. 551 *et seq.* The comment period closed on July 31, 2015. These comments and all other related rulemaking materials are available in the electronic docket via *www.regulations.gov* under Docket ID PHMSA–2014–0098. In section III of this document, PHMSA has summarized the regulatory changes proposed in the NPRM and the public's comments regarding those changes. PHMSA has included a detailed response to the public's feedback and comments.

B. Gas Pipeline Advisory Committee

Under 49 U.S.C. 60115, the Gas Pipeline Advisory Committee (GPAC) is a statutorily mandated advisory committee that advises PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas pipelines. The Pipeline Advisory Committees were established under the Federal Advisory Committee Act, Public Law 92–463, 5 U.S.C. App. 1–16, and the Federal Pipeline Safety Statutes, 49 U.S.C. ch. 601. The GPAC consists of 15 members, with membership equally divided among Federal and State agencies, the regulated industry, and the public. The GPAC advises PHMSA on the technical feasibility, practicability, and cost-effectiveness of each proposed pipeline safety regulation.

On June 1–3, 2016, the GPAC met in Arlington County, VA. Seven members of the GPAC were in attendance: One representing government, three representing the public, and five representing industry. One member representing the public, one representing industry, and one representing government were absent; additionally, there were 3 vacancies for government representatives and one vacancy for a public representative. During the meeting, the GPAC considered the regulatory proposals of the NPRM, discussed the comments on the NPRM from the public and the pipeline industry, and recommended changes to the NPRM. The record of this meeting, including full transcripts, is filed under Docket Number PHMSA–2016–0032, available at both *regulations.gov* and on the PHMSA meeting page at *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=113.*

The GPAC, in a unanimous vote, found the NPRM, as published in the **Federal Register**, and the Draft Regulatory Evaluation technically feasible, reasonable, cost-effective, and practicable provided PHMSA incorporated recommended amendments agreed upon by the committee. PHMSA staff has reviewed and incorporated the GPAC's recommendations into this final rule to the extent practicable. Part III of this document summarizes these discussions and recommendations in greater detail under the respective individual topics.

III. Analysis of Comments and PHMSA Response

In the NPRM published on May 21, 2015, PHMSA solicited public comment on whether the potential amendments put forward in the NPRM would enhance the safety of plastic pipe in gas transmission, distribution, and gathering systems, and on the costs and benefits associated with these proposals. PHMSA received comments on the NPRM from 39 entities, including:

- Fifteen pipeline operators;
- Eight pipeline or manufacturer trade associations;
- Six manufacturers;
- Five private citizens;
- Three consultants;
- Two government entities, including an association of State pipeline regulators;
- One citizen group; and
- One pipeline services company.

The following subsections summarize PHMSA's proposals, each of the relevant issues raised by commenters concerning those proposals, and PHMSA's response to those comments. Comments and corresponding rulemaking materials received may be viewed at *www.regulations.gov* under docket ID PHMSA–2014–0098.

A. Tracking and Traceability

(1) PHMSA's Proposal

In the NPRM, PHMSA proposed to amend § 192.3 to define "traceability information" and "tracking information" and to amend §§ 192.321 and 192.375 to establish standards requiring operators to properly and consistently track and trace pipe and components within their system. The proposed tracking information included the location of each section of pipe, the individual who joined the pipe, and components within the pipeline. The proposed traceability information included the location of pipe and components; manufacturer; production; lot information; size; material; pressure rating; temperature rating; and as appropriate, other information such as type, grade, and model. PHMSA proposed to amend § 192.63 to require operators to adopt the tracking and traceability requirements in ASTM F2897–11a, "Standard Specification for Tracking and Traceability Encoding System of Natural Gas Distribution Components (Pipe, Tubing, Fittings, Valves, and Appurtenances)," issued in November 2011, (ASTM F2897–11a), and proposed that operators must record the tracking and traceability data and retain it for the life of the pipe.

(2) Comment Summary

PHMSA received comments supporting the proposed revisions from NAPSR and Dr. Gene Palermo of Palermo Plastics Pipe (P3) Consulting.

(Palermo). Palermo praised the tracking and traceability standards in ASTM F2897–11a and noted that it would bring American operators more in line with International Standards Organization (ISO) tracking and traceability standards. Though the American Public Gas Association (APGA) had specific concerns about technology and costs, it described the collection of tracking and traceability information as "a laudable goal" and further noted that "operators no doubt wish this capability existed when PHMSA issued advisory bulletins about brittle-like cracking problems with Century Pipe, DuPont Adyl A piping manufactured before 1973 and polyethylene gas pipe designated PE 3306."

AGA, APGA, the Texas Pipeline Association (TPA), the Northeast Gas Association, National Grid, AGL Resources, Atmos Energy Corporation, CPs Energy, Questar Gas Company, National Fuel Gas Distribution Corporation, SoCal Gas and San Diego Gas and Electric (SDG&E), NiSource Incorporated, and Norton McMurray Manufacturing Company (NORMAC) submitted comments suggesting that the plastic pipe tracking and traceability provisions should be dropped entirely from the rulemaking. Many operators echoed AGAs concern that a tracking and traceability program would be economically significant, and that full consideration of the costs, benefits, and alternatives that program would slow the adoption and implementation of other portions of the rule.

Additionally, those commenters maintained that tracking and traceability requirements should be considered in a separate rulemaking for all material and system types, rather than piecemeal and only for plastic pipe in this rulemaking. The commenters suggested that consistent regulation of all system types would avoid regulatory uncertainty. AGA, APGA, National Fuel, NiSource, SoCal Gas and SDG&E, and Southwest Gas (SW Gas) all proposed convening a working group to discuss options for moving forward with a separate, comprehensive tracking and traceability rule. National Grid estimated a compliance cost of $8.1 million a year for 14,968 plastic pipe miles, and SW Gas estimated $10 million to $20 million in startup costs and $1 million to $2 million in annual costs. APGA, the Plastics Pipe Institute (PPI), NORMAC, R.W. Lyall and Company (Lyall), Thomas M. Lael, National Fuel Gas, City Utilities, and TPA submitted comments, indicating that markings should only have to be permanent up to the time of installation. Commenters argued that truly "permanent" markings are not currently technically feasible, stating that the information is only needed at the time of installation; after the information has been recorded into a recordkeeping system, the physical markings are no longer necessary. PPI notes that with current technology and practice, markings are designed to last only three years in an underground environment

APGA commented that the proposal would be significantly burdensome to small public operators and that it would be reasonable to expect markings to remain intact 20 years after the pipe was made. Lyall requested clarification about what was expected by the term "permanent markings" and whether an operator's records were sufficient to meet those requirements.

APGA suggested that if PHMSA did move forward with a tracking and traceability program, it should only collect the data required by the six fields prescribed under ASTM F2897–11a: Component manufacturer, manufacturer's lot code, production date, material, type and size. Both Lyall and Continental Industries concurred. PPI noted that deviating from ASTM F2897–11a would require manufacturers to revamp their marking systems away from the standard and would potentially require new barcoding systems. SW Gas suggested that a tracking and traceability working group could potentially revise ASTM F2897 to incorporate any additionally-needed data fields in the future.

AGA, Northeast Gas Association (NGA), National Fuel Gas Distribution Corporation (NFGDC), PPI, Lyall, and City Utilities recommended that, regardless of the specific tracking and traceability provision in the final rule, PHMSA should use a "phased-in" approach for implementation. City Utilities commented that it was not opposed to the recordkeeping of material data but requested an extended timeframe to create an implementation plan that considered budget costs. Commenters suggested three to five-year phase-in periods for tracking and traceability recordkeeping requirements.

The GPAC discussed this topic at length and ultimately recommended that PHMSA phase-in the tracking and traceability provisions by establishing a compliance deadline of one year for ASTM F2897–11a-compliant markings and a deadline of five years for recordkeeping requirements. The GPAC further recommended that PHMSA limit the marking and traceability requirements to the categories in ASTM F2897–11a and revise the permanent marking standard to a requirement that markings on plastic pipe and components be legible at the time of installation.

(3) PHMSA Response

In response to comments on the tracking and traceability recordkeeping requirements proposed for §§ 192.63, 192.321(j) and 192.375(c), PHMSA is delaying final action on these proposals until a later date. PHMSA expects to consider all the comments and the recommendations of the GPAC related to tracking and traceability recordkeeping after further evaluation of the costs and benefits of this issue. These issues may be revisited in either a subsequent final action or a new rulemaking project.

Plastic pipe must still be marked with the 16-character ASTM F2897–11a markings, which are included in the 2012 editions of the material standards for PE and PA–12 pipe. Incorporating the 2012 editions of the material standards help narrow the gap between the regulations and the latest consensus standards, and adopting the 16-character ASTM F2897–11a markings within those materials standards will help to phase in standardization to how component attributes are marked and eventually captured in asset management systems. The final rule does not include most of the additional marking performance regulations previously proposed in § 192.63(e), such as permanence requirements and instead defers to the language in the material standards. PHMSA notes that some of the standards incorporated by reference in this final rule contain their own durability requirements which also vary on whether the marking is on pipe, fitting or another component. For example, section 7 for respective material specific standards (*i.e.* ASTM D2513–12ae1 for PE, ASTM F2785–12 for PA–12 and ASTM F2945–12a for PA–11) states that for pipe all required markings shall be legible, visible, and permanent. The standards go on to say to ensure permanence, markings shall be applied so it can only be removed by physically removing part of the pipe wall, shall not reduce the wall thickness to less than the minimum value of the pipe, not have any effect on the long-term strength of the pipe, and not provide leakage channels when elastomeric gasket compression fittings are used to make joints. The marking section for fittings on the other hand does not have such explicit requirements on durability or mention permanence. The standard for plastic valves, ASME B16.40–2008, states that only certain markings on valves must be permanently affixed, while others can be made by any means.

PHMSA is including language in § 192.63(e) that markings must be legible until time of installation based on public comments and GPAC recommendations. The language is intended to provide clarity given the confusion with how the marking portions of the material specific standards (such as ASTM D2513–12ae1 for PE, ASTM F2785–12 for PA–12 and ASTM F2945–12a for PA–11) are written and what the ultimate requirements are. For example, it is not entirely clear in section 7.1 of ASTM D2513–12ae1, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings," issued on April 1, 2012, (ASTM D2513–12ae1), whether all required markings (including the 16-character ASTM F2897–11a markings in section 7.6) be "legible, visible, and permanent" per the standards or if the permanence requirements only apply to the more conventional print line information in place prior to the 2012 version and the 16-character marking is an additional requirement with different durability requirements. While manufacturers also commented that it was not feasible to make ASTM D2897 markings permanent and readable for several years after installation without additional costs, it is certainly feasible to print markings legible until the time of installation. This new regulatory language addresses issues raised in public comments and by the GPAC concerning confirming the durability of markings, and help ease any potential regulatory burdens as a result of confusion with permanency and durability requirements. Furthermore, PHMSA is still including a one-year implementation period based on public comments and GPAC recommendations to allow manufacturers additional time to incorporate the new requirements, particularly for the 16-character marking. PHMSA understands many manufacturers are already implementing the 16-character marking but some have not yet, with many manufacturers on both sides waiting to get clarity of expectations on durability.

In the interim, PHMSA expects all distribution operators to already be collecting some form of tracking and traceability information, since the Distribution Integrity Management Program (DIMP) regulations in § 192.1007(a)(5) require that operators capture and retain data on the location where new pipeline is installed and the material of which it is constructed.

B. Design Factor for PE

(1) PHMSA's Proposal

PHMSA proposed to amend the design pressure equation in § 192.121 to increase the design factor (DF) for PE pipe from 0.32 to 0.40.

The design pressure for PE pipe and other thermoplastics are based first on a Hydrostatic Design Basis (HDB) rating, which refers to the categorized long term hydrostatic strength for a given material. The HDB value is sometimes also considered a measure of the ultimate long term strength of the material. Industries then apply an additional design factor multiplier to the HDB rating to account for potential long term effects based on engineering considerations of how the HDB of the material was derived in conjunction with the behavioral properties of the material, and the specific product they are transporting. The allowable design pressure for plastic in § 192.121 is based on a number of factors, including the HDB rating, wall thickness and diameter or standard dimension ratio (SDR), and design factor. An increase in design factor allows for the use of slightly thinner wall to achieve the same design pressure.

To illustrate how the design factor affects the design of plastic pipe, examples using the design pressure calculation are shown below. The design pressure formula in § 192.121 is expressed in one of two ways:

$P = 2 \times S \times (t/(D - t)) \times DF$

or

$P = 2 \times (S/(SDR - 1)) \times DF$

Where S = the HDB rating; t = specified minimum wall thickness; D = specified outside diameter; DF is the design factor; and SDR the standard dimension ratio (ratio of average specified outside diameter to minimum specified wall thickness.)

A common pipe material is PE4710 which has an HDB rating of 1600 at 73 °F. A common pipe size is 4-inch PE SDR 11 which has an average specified outside diameter of 4.5 inches and specified minimum wall thickness of 0.409 inches. If these values are applied to the first equation above, the design pressure would be:

$P = 2 \times 1600 \times (0.409/(4.5 - 0.409)) \times 0.32 = 102.4$

Applying them to the second equation above, design pressure would be:

$P = 2 \times (1600/(11 - 1)) \times 0.32 = 102.4$ psi

If the design factor is changed from 0.32 to 0.40, it also changes the result of the calculation in the design pressure formula. If an operator wants to maintain an operating pressure of around 102.4 psi with the new design factor, they could do so using a slightly thinner wall pipe of SDR 13.5, or minimum specific wall of 0.333 inches. The formulas below illustrate how the new design factor allows an operator to use the same design pressure with thinner wall pipe.

$P = 2 \times 1600 \times (0.333/(4.5 - 0.333)) \times 0.4 = 102.3$ psi

or

$P = 2 \times (1600/(13.5 - 1)) \times 0.4 = 102.4$psi

Alternatively, an increase of design factor with use of slightly thinner wall pipe allows an operator to increase throughput and design pressure if all other variables remain the same, as long as the design pressure doesn't exceed the limitations called out in the regulations (such as 125 psi and minimum wall thickness.)

The current design factors for thermoplastic pipe were established decades ago based on general experience with materials at the time and attempts at standardization. As an example, water used a 0.5 design factor for decades. For gas pipe, additional safety factors (sometimes also called strength reduction or derating factors) were applied to the water DF: an additional 0.8 multiplier covers long term effects from constituents in fuel gas, and another 0.8 multiplier compensates for use at increased temperatures above 73 °F. If those two multipliers are applied on top of 0.5 DF for water (or $0.5 \times 0.8 \times 0.8$) the resulting DF is 0.32 for gas.

On August 14, 2009, PHMSA received a petition from AGA to allow for a 0.40 design factor for PE pipe based on research and technical justifications performed by the Gas Technology Institute (GTI; July 16, 2007) and to include certain limitations by type of material and wall thickness.[1] A primary justification for considering raising the design factor is consideration of newer, better performing materials of today and changes in other industries like water, but still applying the same safety factors in place for gas. The water industry has changed their safety factor from 0.5 to 0.63 in standards such as ANSI/AWWA C901–08, Polyethylene (PE) Pressure Pipe and Tubing, ½ in. (13 mm) through 3 in. (76mm), for Water Service (October 1, 2008.) The 2017 edition of PPI TR–4 allows a design factor of 0.63 for plastic water pipe made of certain PE 4710 materials. Applying the same two derating factor multipliers for gas to the newer DF for water (or $0.63 \times 0.8 \times 0.8$) results in a DF of 0.4 for gas. There are

[1] Docket No. PHMSA–2011–0011, August 14, 2009.

additional safety measures applied if operators want to use the 0.4 DF, including the use of newer materials in place today, the application of a minimum wall thicknesses by pipe size, and a maximum pressure of 125psi.

Since design pressure for plastic pipe is based on a number of variables, including design factor and wall thickness, an increase in design factor would allow for the use of PE pipe with thinner pipe walls manufactured in accordance with ASTM D2513–12ae1 as long as it doesn't go below the minimum wall thickness for a specific pipe size.

(2) Summary of Comments

The majority of commenters, including AGA, APGA, PPI, NGA, NAPSR, NFGDC, TPA, Palermo, and SW Gas, supported this proposal, with several suggesting that a higher design factor would incentivize the use of plastic pipe and provide safety and economic benefits due to its low cost and resistance to traditional corrosion risks. Palermo supported the design factor increase to 0.40 and noted the safe operating history of PE pipe operated to that specification in Canada. Palermo further noted that increasing the design factor would make the material more attractive for operators which it claims would have positive impacts on pipeline safety, stating that going to a 0.4 design factor encourages distribution operators to "extend the use of plastic pipe systems and displace the lower safety related performance of metal pipe with the higher safety related performance of plastic piping system." Palermo noted specifically that plastic pipe systems do not face corrosion risks like metallic pipe systems do.

AGA, PPI, NGA, Evonik Industries, and the MidAmerican Energy Company (MidAmerican) supported the proposal in general but were opposed to restricting the diameter of PE pipe beyond the limitations in ASTM D2513–14e1. The commenters suggested permitting pipe up to 24 inches as provided in the standard. Evonik Industries, a plastic pipe manufacturer and one of the original petitioners, also requested that PHMSA expand the PE, PA–11 and PA–12 minimum wall thickness tables in § 192.121 to include pipe sizes less-than-or-equal-to one-inch Iron Pipe Size (IPS).[2] MidAmerican further requested the inclusion of one-inch Copper Tubing Size (CTS) (another size standard) as a pipe size.

AGA and TPA requested that the proposal for an increased design factor for PE pipe should be applied retroactively to existing pipe made of PE2708 and PE4710. ASTM introduced those compounds in 2008 in ASTM D2513–08b "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings."

The Iowa Utilities Board (IAUB) stated that the wall-thickness tables in the rule should use Standard Dimension Ratio (SDR) rather than Dimension Ratio (DR) in the column heading to be consistent with the design formula for plastic pipe in § 192.121. Additionally, for ease of use, IAUB recommended including a header on the PE and PA tables in § 192.121 indicating to what materials they apply.

DTE Energy (DTE) opposed the proposed 0.090-inch minimum wall thickness for plastic pipe and suggested that PHMSA should retain the current 0.062-inch minimum for PE pipe that they have used in Michigan since 1967. DTE further commented that operators should be allowed to apply the design formula in § 192.121(a), based on the intended use and operating pressure of the pipe, to dictate the minimum required wall thickness.

The PVC Pipe Association, a trade group representing PVC pipe manufacturers, submitted comments broadly opposing PHMSA's proposal to modify the allowed design factor of PE Pipe. The Association opposed the less-conservative design factor of 0.40 until operators could gain more field experience with PE pipe operating at the higher factor. In supporting documentation, the PVC Pipe Association hypothesizes that certain high-density polyethylene (HDPE) pipe grade compounds can be susceptible to microscopic crack propagation in high-pressure water service, though it acknowledged that newer compounds may be more crack-resistant.

The GPAC recommended minor changes to the minimum wall thickness tables to add additional items, and that PHMSA research the procedural possibility of incorporating the more recent ASTM D2513–14e1, which allows PE pipe with a larger maximum diameter. The Committee further requested that PHMSA research the possibility of applying the new design factor retroactively to existing pipe with the same material characteristics specified in the rule. Members of the Committee and representatives of PPI and AGA commented that, except for the diameters allowed currently, ASTM D2513–12ae1 is not significantly different from either the editions issued before or after it. Therefore, allowing previously installed pipe to operate at the increased design factor or allowing the higher diameters permitted in the 2014 standard should be acceptable.

(3) PHMSA Response

In consideration of the comments, PHMSA is revising the final rule to include pipe sizes smaller than one-inch IPS and certain one-inch CTS pipe sizes on the tables for each of the materials modified in the final rule. Specifically, in this final rule, PHMSA has revised the proposed PE wall thickness and the SDR table in § 192.121(c)(iv) for clarity and to include ½′ and ¾′ IPS and CTS sizes. The omission of these smaller-diameter specifications was an oversight; PHMSA did not intend to restrict the use of small-diameter plastic pipe. PHMSA will also revise the PE, PA–11, and PA–12 tables per the recommendations of the IUB for consistency and ease of use.

In response to comments from DTE, PHMSA notes that the 0.090-inch minimum wall thickness applies to pipes operating at the new 0.40 design factor. At 0.32, operators may still use the design formula in § 192.121 in accordance with the applicable standard. PHMSA is not lowering the minimum wall thickness for 0.40 design factor pipe, as the more conservative wall thickness is necessary to mitigate sidewall fusion and tapping risks, among others, that exist at the higher design factor.

PHMSA notes that while AGA and TPA are correct in their assessment that the design requirements for PE2708 and PE4710 pipe under ASTM D2513–08b are the same as the newly incorporated ASTM D2513–12ae1 edition, this subpart is non-retroactive, therefore, the previous maximum design factor would still apply to existing pipelines.

PHMSA disagrees with comments from the PVC Pipe Association; the supporting data provided in the AGA petition provides proper safety justification for the revised maximum design factor. As described further in the petition, a battery of tests was performed on pipe to evaluate the combined influence of increased internal pressures and other add-on stresses including effects of squeeze-off, rock impingement, surface scratches, earth loading, and bending stresses on the pipe wall. Various types of joints (butt heat fusion, saddle fusion, electrofusion and mechanical joining) were also subjected to long term sustained pressure testing at elevated temperatures. No failures were observed. Both the petition and the final rule do provide minimum wall thickness requirements for an added safety measure. The Vinyl Institute's comments studying the history of legacy

[2] Iron pipe size (IPS) is a pipe size standard still used for polymer pipe.

plastic pipe materials in high-pressure water service is not directly applicable to evaluating the operation of modern PE compounds in gas service.

PHMSA has considered, as requested by the GPAC, the possibility of incorporating a more recent edition of ASTM D2513 and permitting retroactive applicability of the 0.40 design factor. PHMSA is not in the position to adopt the more recent ASTM D2513–14e1, which includes the increased maximum diameter, since this is beyond the scope of the NPRM and PHMSA has not solicited comment on such a proposal. PHMSA will evaluate the new standard and diameter revision for inclusion in future rulemakings.

C. Expanded use of PA–11 Pipe

(1) PHMSA's Proposal

In the NPRM, PHMSA proposed to amend part 192 to allow pipelines made of certain modern PA–11 compounds to operate at pressures up to 250 pounds per square inch gauge (psig) and permit installation of PA–11 pipe with a diameter up to six inches. This would expand the allowable uses of PA–11 from the current regulations which restrict the use of PA–11 pipe to pressures up to 200 psig and nominal pipe sizes of 4 inches or less.

Arkema, the plastics manufacturer that petitioned for this change, cited the growing history of safe operation of PA–11 pipe since 1999 either under special permit or the current restrictions. PHMSA is also permitting arithmetic interpolation of the allowable pressure equation for PA–11. This would allow consistency with how hydrostatic design basis (HDB) [3] is already determined for other thermoplastic pipe materials in § 192.121.

Finally, PHMSA proposed incorporating two PA–11 specific standards by reference. Currently, plastic pipe and fittings made of PA–11 must be manufactured in accordance with the much older editions of ASTM D2513 (1987 and 1999) that are referenced for thermoplastic materials other than PE. Adopting ASTM F2945–12a incorporates over a decade of PA–11 material and design advancements. The standard includes requirements for material composition, design, manufacturing tolerances, strength, crack resistance, and quality control for PA–11 pipe and fittings.

The final rule also incorporates ASTM F2600–09 as a listed specification for electrofusion fittings on PA–11 pipe. An electrofusion fitting is one with a built-in electric heating element. Passing a current through the fitting bonds the pipe. With new material specific standards being added for PA–11 and other standards being added for components in this rule, there is a need to add F2600–09 for Electrofusion PA–11 fittings, similar to how ASTM F1055 is currently referenced for PE Electrofusion Fittings. Like the PE standard, ASTM F2600–09 sets material and performance requirements for PA–11 electrofusion fittings. In order to meet this standard, a manufacturer must demonstrate test a specimen for minimum hydraulic burst pressure, sustained pressure, tensile strength, impact resistance, and joint integrity.

(2) Summary of Comments

Nearly all commenters supported this proposal, including AGA, APGA, PPI, NGA, TPA, TPA, NAPSR, Palermo, and Arkema. Arkema highlighted the operating history of PA–11 pipe in offshore oil and gas use and in gas systems in Australia.

A number of commenters requested additional entries on the minimum wall thickness table for PA–11. AGA, NGA, and Arkema proposed including ¾-inch pipe, and MidAmerican requested the inclusion of one-inch CTS sized pipe in the PE, PA–11, and PA–12 tables. IAUB noted that the rule references CTS pipe, but it is not present on the table.

The Board further stated that CTS values should be included in the minimum wall-thickness table; if not, then references to CTS should be removed from the final rule. The GPAC voted unanimously for these additions to be added to the minimum wall-thickness table.

Palermo and Volgstadt and Associates recommended allowing the use of PA32312 at higher pressures in addition to PA32316 under PA–11. Volgstadt and Associates further noted that since the HDB of PA–11 is 180 °F in PPI TR4, § 192.121 should be revised to allow the installation of pipe using the higher temperature rating. Volgstadt noted that PA32312 could then be safely used in lower-pressure applications where temperatures higher than 140 °F are expected.

(3) PHMSA Response

As noted in the previous discussion on the new design factor for PE Pipe, PHMSA agrees with commenters to revise the tables to include additional sizes, including IPS smaller than one-inch diameter and one-inch CTS. Specifically, PHMSA amended the table in the proposed § 192.121 (d)(2)(iv) to add ½′ and ¾′ IPS and CTS sizes, which match those in the standard and those listed for PE pipe. PHMSA is not including an HDB rating at 180 °F, as not all compounds are rated at that temperature, and inclusion could wrongly imply that operators are permitted to operate any plastic pipe at that temperature. Operators may still interpolate the design formula down from 180 °F. PHMSA is not allowing the use of PA32312 at the higher pressures permitted for PA32316. As explained in the NPRM, PHMSA found it appropriate that operators use PA32316 for such higher-pressure applications due to material characteristics, more specifically, an HDB rating of 3150 psi at 73 °F that can result in a design pressure of 250 psi using SDR 11 and 0.4 DF. The PA32312 material HDB rating of 2500 psi would correlate to a design pressure of 200 psi using the same SDR and DF. Operators may install and use PA32312, but not at the higher pressures permitted for PA32316.

D. Incorporation of PA–12

(1) PHMSA's Proposal

In the NPRM, PHMSA proposed to amend § 192.121 to allow the use of PA–12 pipe in response to a petition for rulemaking from Evonik and UBE (Docket No. PHMSA–2010–0009) at pressures up to 250 psig and for pipe sizes up to 6 inches in diameter, subject to wall thickness limitations described in the petition. These restrictions are consistent with the proposed requirements for PA–11, another polyamide material. The petitioners stated that material testing and experience in pipeline service under special permit have "amply validated" the strength and durability of PA–12 against known threats and failure mechanisms.

PHMSA also proposed to incorporate by reference a number of standards applicable to PA–12 pipe. PA–12 pipe and fittings used under part 192 must be manufactured in accordance with ASTM F2785–12, "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings." The standard defines: Material properties; manufacturing tolerances; test methods and requirements, marking requirements; and minimum quality control program requirements. Manufacturers must comply with these requirements in order to sell pipe as ASTM F2785–12 compliant.

ASTM F2767–12 establishes specifications for electrofusion fittings on PA12 systems. An electrofusion fitting is one with a built-in electric heating element. Passing a current through the fitting bonds the pipe. With new material specific standards being added for PA–12 and other standards

[3] The HDB is a reflection of a plastic pipe's ability to resist internal pressure over long periods of time.

being added for components in this rule, there is a need to add F2767 for Electrofusion PA–12 fittings, similar to how ASTM F1055 is currently referenced for PE Electrofusion Fittings.

(2) Summary of Comments

NAPSR, AGA, APGA, Evonik, NGA, PPI, TPA, and Palermo all expressed support for the proposal. Palermo commented that "PA–12 is very similar to PA–11 and both materials are being used very successfully for gas operations internationally." Palermo further noted that the material has been successful in limited trial use in oil and gas operations in the United States. A number of commenters requested the addition of sizes smaller than one-inch IPS and one-inch CTS for PA–12 similar to those requests made for PE and PA–11.

Evonik commented that the language in the preamble of Section D references to "allow a minimum wall thickness of at least 0.90 inches." The commenter stated that this is a typographical error. A value of 0.090 inches would be consistent with the original petition and the proposed wall thickness tables in § 192.121 for all of the proposed materials. Correcting this error would significantly reduce the required wall thickness for PA–12 pipe. Continental Industries recommended that the material designation code "PA 42316" be included in the PA–12 design requirements in § 192.121(e). The GPAC concurred with this comment.

(3) PHMSA Response

As for PA–11 and PE, PHMSA agrees with the commenters and has revised § 192.121(e)(4) in the final rule to clarify the table by adding ½′ and ¾′ IPS and CTS sizes. In response to comments from Evonik Industries and Continental Industries regarding the typographical error, PHMSA has corrected the minimum wall thickness to 0.090 inches, to conform to the initial petition and includes the material designation code in § 192.121(e).

E. Risers

(1) PHMSA's Proposal

In the NPRM, PHMSA proposed to add a new § 192.204 to part 192, to establish specific requirements for the design and construction of risers for plastic pipe. PHMSA also proposed to incorporate by reference ASTM F1973, "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems" ASTM F1973, which prescribes design requirements for factory-assembled anodeless risers.[4] This specification covers requirements and test methods for the qualification of factory assembled anodeless risers and transition fittings for use in PE pipe sizes through Nominal Pipe Size (NPS) 8, and for PA–11 and PA–12 sizes through NPS 6. No version of this standard is currently in the CFR. The final rule uses this standard to establish the specifications for the design and specimen testing of factory assembled anodeless risers. The standard also provides a definition for Category 1 fittings on plastic pipe. This item will be added as a Listed Specification in Appendix B to Part 192-Qualification of Pipe and Components.

(2) Summary of Comments

AGA, APGA, NAPSR, NGA and P3 Consulting supported GPTC's petition to allow the use of anodeless plastic risers above ground to meter and regulator stations. A number of commenters opposed the structural support requirements for risers in the NPRM as being too prescriptive. Specifically, those commenters opposed the requirement for a three-foot horizontal base leg on risers. AGA, PPI, NGA, TPA, NORMAC, Lyall, Volgstadt and Associates, and Avista Utilities all suggested either deleting the requirement altogether or applying some type of performance standard. AGA, PPI, TPA, NORMAC, and Lyall & Co. proposed language requiring operators to ensure that risers do not bear external loads and are secured against lateral movement. Volgstadt and DTE supported deleting all references to the horizontal base leg. Other commenters supported performance standards in general. The GPAC unanimously voted to recommend removing the requirement for a three-foot horizontal base leg.

A number of commenters representing manufacturers and third party consultants expressed concerns that the exclusive reference to ASTM F1973, which exclusively applies to factory-assembled risers, would effectively prohibit the use of field-assembled risers that are constructed in accordance with ASTM F2509, "Standard Specification for Field-assembled Anodeless Riser Kits for Use on Outside Diameter Controlled Polyethylene and Polyamide-11 (PA11) Gas Distribution Pipe and Tubing" (ASTM F2509). PPI, Lyall, Volgstadt, and Continental Industries therefore recommended incorporating ASTM F2509 into the final rule. NORMAC also recommended incorporating ASTM F1948–15, "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing" (ASTM F1948–15) since, as in many cases, ASTM F2509 riser fittings may have identical requirements to standard fittings under ASTM F1948–15. The IAUB, the Gas Processors Association (GPA), and TPA commented that, as written, the proposed revision could be interpreted to require that all risers be plastic anodeless risers. These commenters suggested the NPRM should either address other types of risers or the title of the section should be written as to explicitly only apply to anodeless risers.

AGA noted that this requirement should not be applicable to risers installed before the effective date.

IAUB requested clarification on whether anodeless risers will be allowed on structures other than metering and regulating stations, such as pressure recording stations or other installations. IAUB further commented that this scenario might be addressed if the riser is considered a main. NORMAC recommended deleting § 192.204(b), arguing that it is duplicative of the proposed § 192.281(e)(4). If not, it suggested ASTM F2509 be incorporated to allow for field-assembled risers.

NiSource commented that the use of the word "rigid" in § 192.204 is unclear and that, specifically, "rigid" typically refers to an "anodeless riser rigid riser casing" as defined in ASTM F1973. The company argued that if this was PHMSA's intent, then § 192.204(c) should be revised to require anodeless risers to have a rigid riser casing. Additionally, NiSource suggested PHMSA revise § 192.375(a)(2) to permit the use of anodeless flex riser casings.

The GPAC voted unanimously to incorporate this provision if the requirement for a three-foot base leg is removed and PHMSA clarifies that the standards do not apply retroactively.

(3) PHMSA Response

PHMSA concurs with the comments and GPAC recommendations requesting the removal of the requirement for a three-foot horizontal base leg in § 192.204(c) and has therefore removed this requirement from § 192.204(c). PHMSA is retaining, however, the requirement that risers be rigid. As noted by one commenter, PHMSA's intent is to require a rigid riser casing for anodeless risers used to attach plastic mains to regulator stations, and so paragraph (c) has been revised to

[4] An anodeless riser is metal-encased plastic pipe carrying gas to a gas meter.

reflect that intent. PHMSA subject matter experts believe that risers to regulator and metering stations must be rigid and secure to ensure safety, noting that unsecured risers are already prohibited per § 192.321. Finally, these requirements are not retroactive and the final rule has been revised to make that clear.

PHMSA has also resolved a number of other issues regarding anodeless risers. The intent of the proposed revision is neither to prohibit field-assembled risers nor to imply that all risers must be anodeless risers. Therefore, in this final rule, PHMSA has revised § 192.204(b) to specify that it applies only to factory assembled anodeless risers. For reasons described in the incorporation by reference portion of the final rule, PHMSA has not added a field-assembled riser standard in this final rule. Operators may still install field-assembled anodeless risers, but PHMSA will consider incorporating relevant standards in future rulemaking efforts. Regardless of riser type, § 192.204(a) still applies.

In response to the IAUB, the revised amendments permit anodeless risers for use outside of metering and regulating stations provided they meet the minimum general requirements of § 192.204(a) and (b). In response to NORMAC, the riser design requirements in § 192.204(b) are broader than the joint standards specified in § 192.281(e)(4).

F. Fittings

(1) PHMSA's Proposal

In the NPRM, PHMSA proposed to amend § 192.281(e) to require operators to use only mechanical fittings or joints that are designed and tested to provide a "seal plus resistance" to lateral forces so that a large force on the connection would cause the pipe to yield before the joint does. PHMSA proposed that such joints, fittings, and connections must meet the requirements of a "Category 1" joint as defined in ASTM F1924–12, "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing" (ASTM F1924–12), ASTM F1948–12, ASTM F1973–13, or ASTM D2513–12ae1 as appropriate.

PHMSA also proposed adding a new paragraph (g) to § 192.455 to clarify that operators must cathodically protect and monitor electrically isolated metal alloy fittings in plastic pipelines that do not meet any of the exemptions in paragraph (f) of that section. Applying cathodic protection to metal fittings on plastic pipe systems helps to control corrosion on those components and therefore reduces the risk of incidents caused by corrosion.

(2) Summary of Comments

NAPSR and Palermo approved of the revisions proposed for this section. Palermo noted that there is "no reason for a gas operator to use anything but a Category 1 mechanical fitting." APGA submitted comments supportive of the requirements to use specified fittings and the cathodic protection requirements, further noting that, "in fact, some fitting manufacturers ship their fittings already pre-coated, with a sacrificial anode attached." On the other hand, though APGA submitted comments supporting cathodic protection requirements in general, it opposed the cathodic protection monitoring requirements for isolated metal fittings. APGA noted that it would require a test station for each fitting, and operators would incur significant costs. APGA further stated that isolated metal fittings do not face the same corrosion risks since they are isolated by the plastic pipe and don't have significant variances in soil conditions that a long metal pipe system does, therefore burdensome monitoring requirements are often not justified.

TPA, GPA, Norton McMurray, Continental Industries, and GE Dresser Pipeline Solutions (GE) submitted comments encouraging the installation of Category 1 fittings but noted that they are not available in the large diameters frequently found in transmission line service.

TPA and GPA suggested revising the requirement to use Category 1 joints to distribution lines only. Norton McMurray and Continental Industries commented that the justification for requiring Category 1 fittings on higher-diameter lines is unsupported and that Category 2 and 3 joints under ASTM D2513, F1924, F1948, or F1973 should be permitted.

AGA, NGA, and TPA argued that the requirement for Category 1 fittings and cathodic protection should only be for newly installed fittings or those uncovered during maintenance. All three commented that a search and replace program would be very costly, with little corresponding safety benefit.

AGA and NFGDC recommended revising § 192.455 to require monitoring every 10 years rather than the proposed requirement to survey 10 percent of the system each year.

After a lengthy discussion, the GPAC recommended replacing the cathodic protection monitoring requirement for certain electrically isolated metal fittings. Instead, the committee recommended that PHMSA mandate a maintenance requirement consistent with operators' integrity management plans. This means that instead of imposing explicit prescriptive monitoring requirements, PHMSA would expect operators to maintain electrically isolated fittings based upon the on a risk posed by the fitting.

(3) PHMSA Response

In this final rule, PHMSA amends the PSR to require Category 1 joints on all regulated plastic gas pipelines as originally proposed. PHMSA and State inspectors, and the incident history described in PHMSA Advisory Bulletin ADB–08–02, issued in March 2008, titled "Pipeline Safety: Issues Related to Mechanical Couplings Used in Natural Gas Distribution Systems" have shown that inadequate joints are a safety risk on plastic pipelines. Requiring the use of Category 1 joints significantly reduces the risk of mechanical joints or fittings loosening over time or getting pulled out. Large-diameter lines are not exempt from this requirement. The fact that Category 1 mechanical joints are not available is not sufficient justification to use weaker Category 2 or 3 mechanical joints since other effective joining methods that don't require mechanical fittings are available, such as heat fusion.

PHMSA acknowledges that there may be issues with only mentioning the three specifications in § 192.281(e)(4), specifically ASTM F1924–12, ASTM F1948–12, or ASTM F1973–13. There are other fittings standards also included in this rule and listed in § 192.7 and Appendix B that would be applicable for other material types. For example, ASTM F2145 "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing" is applicable for PA–11 and PA–12 mechanical fittings. Rather than adding more standards into the regulatory language § 192.281(e)(4) and potentially missing others, PHMSA is instead revising the language in the final rule to say ". . . must be Category 1 as defined by a listed specification for the applicable material . . ." PHMSA has also clarified the final rule to state explicitly that this provision does not apply retroactively. While all new fittings must be cathodically protected, and meet Category 1 requirements, operators do not have to search for and remove existing mechanical fittings that are non-compliant with the new requirements. Therefore, PHMSA has amended §§ 192.281(e) and 192.367 to state in the headings for those sections that they only apply to plastic pipe fittings installed after the effective date of the rule. This change should alleviate any concerns raised in comments related to the cost and complexity of replacing or cathodically protecting existing fittings.

In response to comments and the recommendations of the GPAC, PHMSA is revising the cathodic protection requirements to reference paragraph § 192.455(g) in paragraph (a) of the same section and is modifying the monitoring requirement in § 192.455(g). PHMSA amended the proposed § 192.455(g) to require that all newly installed electrically isolated metal fittings be cathodically protected, and maintained in accordance with the operator's integrity management plan, rather than comply with a prescriptive monitoring requirement. PHMSA notes that the existing § 192.455(a)(2) still applies unless an isolated metal fitting meets any of the conditions in paragraphs (b), (c), or (f) of that section.

G. Plastic Pipe Installation

The NPRM proposed several revisions to part 192 regarding the installation of plastic pipe. A summary of each of these topics is presented below along with a summary of public comments and PHMSA's response.

(1) Installation by Trenchless Excavation

(a) PHMSA's Proposal

The NPRM proposed adding new §§ 192.329 and 192.376 to the PSR to include new minimum requirements for trenchless excavation. PHMSA and the States are aware of a number of incidents related to cross-boring, where plastic pipe installed via trenchless excavation has come in contact with or been installed right through another underground utility, such as a sewer line. These conflicts can damage both the pipeline and the other underground structure. PHMSA therefore proposed that operators must ensure that the excavation path for installation and maintenance activities will provide sufficient clearance from other underground utilities and structures. Additionally, PHMSA proposed that operators be required to use a "weak link" device for plastic pipe through the ground during installation to prevent unnecessary, excessive stresses on the pipeline.

(b) Summary of Comments

Nearly all commenters broadly supported the proposed revisions to the trenchless excavation requirements. DTE and PPI supported the proposal, as did NAPSR, AGA, APGA, TPA, Avista Utilities, and SW Gas with reservations about specific provisions or with suggestions for modifications. Avista recommended "a Weak Link to be used on trenchless installations on mains and services" though it suggested that the type of weak link would be up to the discretion of the operator to define based on sound engineering practices. Like other commenters, Avista specifically referenced using a segment of smaller diameter pipe as a weak link method. PPI supported PHMSA's requirement for a weak link and noted that "a properly selected breakaway swivel provides added assurance against damaged pipe and is good engineering practice." NAPSR recommended requiring operators to pull through an additional 10 feet beyond the exit of the ground during trenchless excavation. If that segment of pipe shows any damage exceeding 10 percent of wall thickness, NAPSR suggested that the operator should be required have to replace the installed segment. Additionally, NAPSR recommended requiring the use of a tracer wire, though it may be installed on an existing steel pipe if its use on the plastic pipe is not feasible.

A member of the public associated with trenchless technology associations suggested alternative language in the trenchless excavation requirements at § 192.329 to require positive identification of other underground structures prior to trenchless installation. Specifically, he suggested requiring operators to ensure that the excavation path "has provided" sufficient clearance rather than "will provide," He noted that modern best practices and technologies, such as closed-circuit television (CCTV) and robotic CCTV could assure positive identification of other underground infrastructure.

AGA, APGA, TPA, PPI, GPA, Avista, DTE, and SW Gas were all supportive of the use of a "weak link" in trenchless excavation but expressed concern that the use of the word "device" could limit operators to commercially available discrete devices. Some operators commented that they use a piece of weaker pipe or an internal lab-designed device as a weak link. The commenters proposed that PHMSA clarify the language so as not to inadvertently prohibit alternative technologies. The GPAC voted unanimously to support these comments. City Utilities suggested that requiring operators to have written procedures for mitigating and preventing cross-bore incidents would be sufficient to ensure safety.

AGA suggested that these requirements should not apply to service lines below 1.25-inch IPS if an analysis of incidents shows that no relevant incidents have occurred.

NGA noted that there are other tools available to operators to avoid damage to pipelines installed by trenchless excavation, and that requiring weak link technologies is shortsighted. NGA recommended that PHMSA host a workshop of operators and industry experts to explore trenchless excavation best practices.

A number of operators had concerns about the proposed requirement that operators ensure that the excavation area is clear of other underground structures. AGA, TPA, and NFGDC proposed that operators only be responsible for providing sufficient clearance from underground-structures known at the time of installation. TPA suggested that if an underground-structure owner does not respond to a one-call notification, the plastic pipe operator has no means to ensure appropriate clearance. GPA recommended that PHMSA either drops the requirement or provide operators with a list of specific steps to achieve compliance. The GPAC voted unanimously in favor of revising the language of this section to require operators to take "practicable steps" to maintain adequate clearance from other underground structures in accordance with "best practice" documents.

(c) PHMSA Response

In this final rule, PHMSA has made a number of changes recommended by commenters and the GPAC. PHMSA has revised §§ 192.329(a) and 192.376(a) to specify that operators must take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and/or structures at the time of installation. Additionally, PHMSA revised the definition of "weak link" in § 192.3 to include "a device or method," which should provide operators more flexibility. These changes address the concerns raised by commenters regarding the flexibility of weak-link options and the need for clarity of an operator's responsibilities. PHMSA has not provided an exception, however, for small-diameter service lines, since small-diameter lines face many of the same risks as larger mains. Additionally, any hazard reduction due to a smaller-diameter pipe is offset by the fact that service lines are typically closer to dwellings and other inhabited structures. PHMSA notes that CCTV technologies may be useful for positive identification of other underground-structures, but the specific recommendations involving CCTV technology have not been subject to notice and comment or cost-benefit analysis. PHMSA may analyze this issue in a future rulemaking after considering the benefits and limitations of CCTV technologies.

Similarly, PHMSA has not implemented the enhanced requirements recommended by NAPSR, but is open to enhancing these requirements in future rulemakings and possibly hosting a public workshop on weak links and trenchless excavation. More information on this topic is available in a white paper titled "Meta-Analysis: Cross Bore Practices" issued by the PHMSA/NAPSR Plastic Pipe Ad Hoc Committee on July 10, 2014.[5]

(2) Joining Plastic Pipe

(a) PHMSA's Proposal

In the NPRM, PHMSA proposed amending § 192.281 to clarify language related to joining plastic pipe. The proposed revisions included clarifying that solvent cement requirements in ASTM D2564–12, "Standard Specification for Solvent Cements for Poly(Vinyl Chloride) (PVC) Plastic Piping Systems" (ASTM D2564–12), apply only to PVC pipe, clarifying that the joining requirements in § 192.281(c) apply to both the pipe and components, requiring heat fusion joints to comply with ASTM F2620–12, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings," issued on August 1, 2012, (ASTM F2620–12), and adding a new paragraphy (e)(3) to require that each fitting used to make a mechanical joint meets a listed specification in Appendix B of part 192.

(b) Summary of Comments

AGA and NFGDC opposed requiring all types of heat fusion joints to comply with ASTM F2620–12. AGA commented that ASTM F2620–12 is primarily intended for saddle-fusion joints on live pipes. AGA also stated that compliance with ASTM F2620–12 would require operators to re-qualify a number of proven joining procedures and eliminating those that differ from the standard. Those two commenters were specifically concerned about the prohibition of methods differing from the standard, particularly with respect to the use of different heater temperatures. TPA requested that PHMSA allow the continued use of existing qualified joining procedures.

APGA supported PHMSA's proposal to require heat-fusion joints to comply with ASTM F2620–12 and the proposed revisions to § 192.281(d), which require all mechanical joints and fittings to be classified as Category 1 as defined in ASTM F1924–12, ASTM F1948–12, or ASTM F1973–13.

Arkema commented that since ASTM F2620–12 is specific to PE only, the regulatory language should refer to this standard for only PE heat-fusion joints. Volgstadt and Associates' comments echoed the concerns of Arkema. Volgstadt also noted electrofusion is not covered under ASTM F2620–12 and suggested that §§ 192.281(c) and 192.285(b) be corrected so ASTM F2620–12 only applies to PE hot plate fusion and not to either electrofusion or PA–11. Volgstadt further recommended either revising § 192.281(c) to replace "plastic pipe" with "PE pipe" to avoid requiring an incompatible standard, or revising future editions of ASTM F2620 to include electrofusion methods and PA–11 materials. APGA, TPA, PPI, NAPSR, PPI, and City Utilities opposed the prohibition of socket-fusion joints above a certain diameter. APGA noted that PHMSA has not provided a rationale for prohibiting socket-fusion on any size of plastic pipe and that the cost of butt-fusion or electrofusion equipment is prohibitive for small operators. APGA further proposed allowing socket-fusion for plastic pipe of four-inch diameter or less. PPI, TPA, NAPSR, and City Utilities concurred. The GPAC voted unanimously to recommend adoption of the comments requesting removal of the socket-fusion diameter restriction.

NORMAC requested clarification as to whether the proposed § 192.281(e) requires manufacturers of factory-assembled anodeless risers to meet a listed specification as § 192.271(b) states that the requirements do not apply to joints made during the manufacture of a product.

NORMAC also proposed that the requirement for qualifying joining procedures by operators must be separate from the qualification of designs for manufacturers' joint and fitting specifications. ASTM D2513 should not be applied to mechanical joint manufacturing regulations as it is a standard specification rather than a testing performance criterion. NORMAC further suggested deleting § 192.281(e)(1) as it is not written in performance language and is unnecessary as there is no evidence of material incompatibility of plastic materials. It further commented that §§ 192.281(e)(2) and 192.281(e)(3) are duplicative. NORMAC also strongly opposed implying that elastomers in mechanical fittings and joints can loosen or degrade over time. NORMAC stated that PHMSA must provide publicly cited evidence that elastomer degradation has been a systemic problem or retract unsupported statements on mechanical joints from the docket and elsewhere.

(c) PHMSA Response

PHMSA disagrees with AGA's proposal to restrict ASTM F2620–12 to saddle-fusion joint procedures only. The standard includes procedures for other types of joints.

Regarding concerns on whether operator joining procedures that may differ from ASTM F2620–12 may not be acceptable and would have to be requalified, it would depend on how exactly they differ. PHMSA would expect that if an operator can demonstrate the differences are sound and provide an equivalent or better level of safety compared to ASTM F2620–12 it could be found acceptable. However, if operator procedures are found to be lacking in any way, such as a heating temperatures used, fusion pressures or cooling times, they may not be acceptable.

PHMSA agrees with commenters that noted ASTM F2620–12 is a PE only standard and does not cover electrofusion. PHMSA has made revisions for clarification. For electrofusion, it is not explicitly listed in the code language in §§ 192.281 or 192.285, but electrofusion fittings and joints would ultimately need to comply with requirements of ASTM F1055, a listed specification for electrofusion.

PHMSA supports Volgstadt's suggestion to consider revising ASTM F2620–12 to include electrofusion and other thermoplastic material types (including PA–11), but defers to the ASTM process on how best it should be handled and ultimately vetted.

PHMSA's intent regarding socket-fusion joints was not to prevent the common use of safe components. Therefore, PHMSA has removed the diameter restrictions for socket-fusion joints from § 192.281(c)(2). Such fittings must still comply with the listed specification, which may have their own diameter restrictions.

In response to comments from NORMAC, PHMSA notes all parts of factory assembled risers must comply with the appropriate listed specifications. PHMSA disagrees that § 192.281(e)(2) is duplicative with § 192.281(e)(3) that is incorporated by this final rule; § 192.281(e)(3) requires that newly installed mechanical fittings must meet a listed specification, while § 192.281(e)(2) is a general requirement that applies to all mechanical joints on plastic pipe regardless of the applicable material. Further comments regarding

[5] *http://primis.phmsa.dot.gov/dimp/docs/MetaAnalysis_Cross_bore_practices_07102014%20final%20R3.pdf.*

the appropriateness of existing code language regarding gasket material compatibility or comments on past advisory bulletins related to observed wear of elastomers are not within the scope of the rulemaking.

(3) Qualifying Joining Procedures

(a) PHMSA's Proposal

In the NPRM, PHMSA proposed to amend § 192.283(a)(1)(i) to incorporate an updated version of ASTM D2513–12ae1 for PE pipe and the new joining standards applicable to PA–11 and PA–12 pipe in ASTM F2945–12a and ASTM F2785–12 respectively when determining the sustained pressured test or minimum hydrostatic burst test. PHMSA also proposed to remove § 192.283(d), which permitted operators to use pipe or fittings manufactured prior to July 1, 1980, if they are joined in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe. Together these changes will codify modern joining procedures for PE, PA–11, and PA–12 pipeline systems.

(b) Summary of Comments

NAPSR supported PHMSA's proposal. NORMAC commented that the three listed specifications in § 192.281(e)(4) do not contain language for qualifying operator joining procedures, unlike the existing provisions in § 192.283. NORMAC further recommended revision of § 192.283 to separate the specification and testing requirements for manufacturers from the regulatory performance standards for operator procedures currently in the PSR.

(c) PHMSA Response

PHMSA believes NORMAC may have incorrectly interpreted the NPRM proposed language in § 192.281(e)(4) and § 192.283(b) related to mechanical joints and applicable pipe standards for qualifying joining procedures. However, PHMSA can see reasoning for the confusion and believes there is the possibility that others could misinterpret as well. The three specifications that were named in § 192.281(e)(4), specifically ASTM F1924–12, ASTM F1948–12, or ASTM F1973–13, were included only to help provide references for the definition for Category 1 depending on the specific type/material of fitting involved, since PHMSA doesn't have an explicit definition for Category 1. The language in § 192.283 (b) that talks about being "qualified in accordance with a listed specification based upon the pipe material" is referring to a listed specification in Appendix B for pipe depending on the material (for instance ASTM D2513–12ae1 for PE, ASTM F2785–12 for PA–12, or ASTM F2945–12a for PA–11.) PHMSA believes each of those material specific standards or the standards they reference for mechanical fittings (for instance the PA–11 and PA–12 material standards require mechanical fittings to conform to ASTM F2145) provide suitable language related to testing that can help qualify joining procedures. Since each of the standards is written slightly differently and in some cases have additional material specific considerations compared to what was written in § 192.283 previously, PHMSA believes it is appropriate to defer to the listed specification. As mentioned in the PHMSA response in § 192.281(e)(4) and given the confusion between the language in § 192.283 (b), the three listed specifications in § 192.281(e)(4), and considering there are additional listed specifications in Appendix B that also contain material specific considerations and can help with definition for Category 1, PHMSA is editing § 192.281(e)(4) to more generically point to a listed specification. This would also make §§ 192.281(e)(4) and § 192.283 (b) more consistent with how the language is written related to listed specifications.

(4) Qualifying Persons To Make Joints

(a) PHMSA's Proposal

The NPRM proposed amending § 192.285 by modifying the requirements for qualifying persons to make joints. PHMSA proposed to add reference to ASTM F2620–12 to the joiner qualification requirements in § 192.285 (b)(i) as an option for PE pipe. ASTM F2620 provides information on what constitutes a visual acceptable or unacceptable joint.

(b) Summary of Comments

NAPSR supported PHMSA's proposal. The PPI supported the incorporation of ASTM F2620–12 but noted that certain standards it had developed, including PPI TR–33 and TR–41, were equally sound procedures and should also be incorporated. Arkema opposed deleting the joint-testing details from § 192.285. Arkema commented that ASTM F2620–12 is limited only to PE and that § 192.285 should instead refer to ASTM F2620–12 for only PE heat-fusion joints while other joining qualification tests could be regulated under the existing § 192.285 language. Volgstadt and Associates' comments echoed these concerns. Volgstadt also suggested that §§ 192.281(c) and 192.285(b) be corrected as ASTM F2620–12 only applies to PE hot plate fusion and applies to neither electrofusion nor PA–11. Volgstadt recommended either revising § 192.281(c) to replace "plastic pipe" with "PE pipe" to avoid requiring an incompatible standard, or revising a future ASTM F2620 edition to include electrofusion methods and PA–11 materials.

SoCal Gas and SDG&E jointly commented that ASTM F2620–12 does not address a number of safety concerns that have been incorporated into qualified heat-fusion procedures. They proposed that PHMSA continue to allow the use of procedures qualified under the testing performance standard in § 192.283. They argued that the existing testing standards under § 192.283 are more stringent than the proposed ASTM F2620–12 and should not be eliminated. The commenters proposed that § 192.285 should use more general language that allows the option of relying on sound engineering requirements developed by an operator's own lab testing.

(c) PHMSA Response

The NPRM did not propose to delete any of the testing requirements in the existing § 192.285. ASTM F2620–12 is being incorporated as an additional minimum standardized practice for PE materials to address many gaps and inconsistencies seen through the years with the joining procedures. Regarding concerns on whether operator joining procedures that may differ from ASTM F2620–12 may not be acceptable, it would depend on how they differ. PHMSA would expect that if an operator can demonstrate through an inspection of the procedures that the differences are sound and provide an equivalent or better level of safety compared to ASTM F2620–12 it could be found acceptable. However, if operator procedures are found to be lacking in any way when comparing the operator procedures to ASTM F2620–12, and reviewing results of testing results used to qualify the procedures, they may not be acceptable.

PHMSA agrees with commenters that noted ASTM F2620–12 is a PE only standard and does not cover electrofusion; PHMSA has made revisions for clarification. For electrofusion, it is not explicitly listed in the code language in §§ 192.281 or 192.285 but electrofusion fittings and joints would ultimately need to comply with requirements of ASTM F1055, a listed specification for electrofusion.

PHMSA supports Volgstadt's suggestion to consider revising ASTM F2620–12 to include electrofusion and other thermoplastic material types (including PA–11) but defers to the

ASTM process on how best it should be handled and ultimately vetted.

(5) Bends

(a) PHMSA's Proposal

In the NPRM, PHMSA proposed to revise § 192.313 to prohibit bends in plastic pipe less than the minimum radius specified by the manufacturer. While plastic pipe is somewhat elastic, a bend radius that is too small may compromise the structural integrity of the pipe.

(b) Summary of Comments

AGA and NAPSR supported PHMSA's bend-specification proposal. PPI and GPA noted a typographical error in the proposed § 192.311(d), stating that PHMSA most likely intended to prohibit bends less than the minimum radius specified by the manufacturer rather than the maximum.

(c) PHMSA Response

PHMSA agrees with the commenters about the typographical error and has corrected § 192.313 to prohibit bends smaller than the minimum radius specified by the manufacturer.

(6) Installation of Plastic Pipe

(a) PHMSA's Proposal

In the NPRM, PHMSA proposed to amend § 192.321 to increase the minimum wall thickness of all plastic pipe to 0.090 inches (2.29 millimeters), to require that operators protect plastic pipe from damage when installing it within a casing, to establish backfill requirements during excavation, and to allow operators to terminate plastic mains aboveground under certain conditions.

(b) Summary of Comments

APGA supported the proposals to require protecting encased plastic pipe from damage at casing entrance and exit points in § 192.321(f), and to allow certain plastic mains to terminate above ground in § 192.321(i).

NAPSR, AGA, APGA, PPI, SW Gas, TPA, and NFGDC submitted the following comments critical of the proposed backfill requirements in this section:

- The commenters generally concurred with AGA's critique that the phrase "properly compacted" inadvertently added a prescriptive requirement that required further clarification. AGA commented that including the phrase "properly compacted" requires operators to quantify soil compaction, but does not define what is an acceptable level of quantification.
- SW Gas commented that PHMSA must clearly specify compaction and documentation requirements.
- AGA recommended simply requiring that lines be properly supported.
- NAPSR proposed removing the phrase "such as rocks of a size exceeding those established through sound engineering practices" from § 192.321(i)(1).
- SW Gas argued that backfill requirements are typically prescribed and enforced by the construction permitting agency and therefore, a PHMSA specification was unnecessary.
- PPI recommended that PHMSA clarify the requirements through the incorporation of "PPI Handbook for PE Pipe, Chapter 7—Underground Installation of PE Pipe."

As for the proposed change in the minimum wall thickness requirement for new and replaced pipe, three entities submitted comments:

- APGA noted that the proposed requirement for a minimum wall thickness of 0.090 inches for plastic pipe might be inconsistent with the proposed § 192.121(b)(3), which established a minimum plastic pipe thickness of 0.062 inches.
- APGA did not have a strong opinion either way but recommended that the rule be revised to remain consistent.
- DTE strongly opposed any change from the current minimum wall thickness of 0.062 inches.

The GPAC recommended approval of all the proposed changes in the NPRM, provided that PHMSA removed the enhanced backfill requirements.

(c) PHMSA Response

PHMSA concurs with the comments and the recommendations of the GPAC, and has therefore removed the proposed enhanced backfill requirements from the final rule. PHMSA notes that operators must still avoid issues with backfill under the more general requirements in §§ 192.319(b) and 192.361(b). The existing § 192.319(b)(1) already requires that backfill for transmission lines provide adequate support for the pipeline, while § 192.361 has similar requirements for service lines. Section 192.319(b)(2) further requires that operators must backfill transmission lines with materials that prevents damage.

For clarity, PHMSA has revised § 192.321 to refer to § 192.121 rather than repeat the minimum wall thickness requirement.

(7) Service Lines; General Requirements for Connections to Main Piping

(a) PHMSA's Proposal

In the NPRM, PHMSA proposed to add a new paragraph (b)(3) to § 192.367 that required operators use Category 1 joints for service line connections to gas mains. Category 1 joints are defined in ASTM F1924–12, ASTM F1948–12, or ASTM F1973–13 for the applicable material and must provide a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25 percent elongation of the pipe or would cause the pipe to fail outside of the joint area during the tensile strength test prescribed by the applicable standard. In other words, the fitting must be designed such that the pipe will fail before the joint does.

(b) Summary of Comments

NAPSR supported PHMSA's proposal. NORMAC submitted comments arguing that, in the context of § 192.367(b), the word "connection" is synonymous with "joint." Therefore, NORMAC suggested that the proposed § 192.367(b)(3) and the existing § 192.367(b)(1) should be deleted, as these regulations repeat §§ 192.281(e)(3) and 192.283(b), which specify compression fittings. NORMAC further commented that gaskets are used beyond just connections to mains. Therefore, the performance standards for gaskets should be included in the general requirements in § 192.273 while § 192.367 should only address issues unique to main connections.

(c) PHMSA Response

PHMSA recognizes that § 192.367(b) and the existing language in §§ 192.81(e)(3) and 192.283(b) may be redundant; however, § 192.367 applies to more than just plastic pipe materials and therefore has not been removed because referencing these standards in both sections is prudent. The gasket requirements proposed in § 192.367 are specific to service line connections to mains. PHMSA may consider standards for gaskets in the future if PHMSA identifies a safety need for such standards.

PHMSA acknowledges that there may be issues with only mentioning the three specifications in § 192.367(b) specifically ASTM F1924–12, ASTM F1948–12, or ASTM F1973–13. There are other fittings standards also included in this rule and listed in Appendix B that would be applicable for other material types. For example, ASTM F2145 "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical

Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing" is applicable for PA–11 and PA–12 mechanical fittings and also has a definition for Category 1. Rather than adding more standards into the regulatory language § 192.367(b) and potentially missing others, PHMSA is instead revising the language in the final rule to say ". . . must be Category 1 as defined by a listed specification for the applicable material . . ." As described above, the mechanical fitting standards all define a category 1 fitting as one in which the surrounding pipe fails before the joint during tensile strength testing.

(8) Equipment Maintenance; Plastic Pipe Joining

(a) PHMSA's Proposal

In the NPRM, PHMSA proposed adding a new § 192.756 to establish minimum maintenance, calibration and testing, and recordkeeping provisions for plastic pipe joining equipment. Proper calibration and maintenance of plastic pipe joining equipment is important due to the difficulty in assessing the quality of field joints.

(b) Summary of Comments

NAPSR and Lael supported the proposed recordkeeping requirements. Lael suggested strengthening the requirements under this part and suggested adding a requirement for operators to have written procedures for equipment calibration and maintenance. Specifically, Lael commented that daily or periodic adjustment records are also important, and therefore recommended eliminating the recordkeeping exception for those records. AGA, APGA, GPA, TPA, Avista Utilities, DTE, and SW Gas submitted comments that agreed with the importance of proper equipment maintenance and calibration but critical of prescriptive recordkeeping requirements. The commenters viewed the proposed § 192.756 as excessively prescriptive, limiting, and burdensome. The commenters claim that, as proposed, the NPRM was not sensitive to varying maintenance and recordkeeping requirements recommended by equipment manufacturers. The GPAC recommended that PHMSA withdraw the proposed changes in paragraphs (b) through (d) of § 192.756.

GPA suggested alternative language clarifying that equipment maintenance and calibration must be appropriate for the equipment being evaluated

(c) PHMSA's Response

In consideration of the comments and the recommendations of the GPAC, PHMSA has removed the additional calibration and recordkeeping requirements in paragraphs (b) through (d). Therefore, the retention of records of daily equipment calibrations and adjustments suggested by Lael has not been implemented. Commenters suggested that the proposed requirements were overly prescriptive and burdensome. PHMSA may revisit this issue if problems are identified in the future. The final rule retains the requirement that operators must maintain joining equipment in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.

H. Repair of Plastic Pipe

(1) PHMSA's Proposal

In the NPRM, PHMSA proposed to amend the plastic pipe repair criteria in § 192.311 to require operators to replace plastic pipe or components if they have a scratch or gouge exceeding 10 percent of the wall thickness. The purpose of the proposed amendment was to add a clearer standard of what constitutes the type of defect that necessitates repair. The current § 192.311 merely states that an operator must repair or remove "[E]ach imperfection or damage that would impair the serviceability" of plastic pipe.

PHMSA further proposed adding a new § 192.720 to prohibit the use of leak repair clamps as a permanent repair on plastic gas pipelines. PHMSA and States have observed issues where some operators have used stainless steel band clamps, intended and designed for temporary repairs on plastic pipe used in gas distribution, as a permanent repair solution. While clamps can be an effective temporary solution in certain situations, such as during an incident to stop the release of gas, PHMSA believes that these clamps should be used only as a temporary repair measure until the pipe can be replaced. PHMSA is also aware of at least one manufacturer that has issued a letter saying its repair clamps are intended for temporary repairs only and should be replaced with a more permanent solution.

(2) Summary of Comments

NAPSR supported both the repair standard for plastic pipe and prohibiting the permanent use of leak repair clamps. Regarding the 10-percent-gouge-depth repair criteria, PPI "supports this proposal as a reasonable and conservative maximum scratch or gouge depth." However, PPI stated that wider tolerances were acceptable since their research showed that 30 percent gouges were found to not have significant long-term performance impacts. PPI commented that less-precise methods such as visual inspections were sufficient for determining gouge depth and should be allowed.

AGA, APGA, and TPA were critical of the 10-percent-gouge-depth threshold for requiring repair or replacement. AGA noted that the 10-percent threshold is an industry rule of thumb that is too stringent for a regulatory requirement and instead proposed a 20-percent threshold as a reasonable repair standard.

AGA and NGA had concerns that the proposed § 192.311(a) as written could prevent the use of electrofusion sleeves for plastic pipe repair.

The GPAC voted unanimously to recommend approval of these provisions, conditioned on the removal of the 10-percent threshold for repair criteria and the clarification that the prohibition on mechanical leak-repair clamps would not require operators to remove existing clamps. Members of the GPAC likewise considered the 10-percent gouge depth criteria to be an industry rule of thumb that was too stringent for a regulatory requirement. While the GPAC did not recommend implementing the 10-percent threshold for repair criteria, members did agree that some sort of repair criteria for plastic pipe was necessary. The GPAC recommended that PHMSA and the Committee support research to develop technically acceptable plastic pipe repair criteria in the near future.

(3) PHMSA's Response

Based on the recommendations of the GPAC, PHMSA has removed the proposed repair criteria from the final rule and therefore did not incorporate the alternative 20-percent-gouge-depth repair criteria proposed by AGA and APGA. PHMSA believes it is appropriate to seek additional technical data and public comment on any proposed repair criteria for plastic pipe. PHMSA intends to revisit this issue and will consider proposing plastic pipe repair criteria in future rulemaking.

PHMSA inspectors have identified the permanent use of leak repair clamps on plastic pipe as an inadequate and risky practice. Furthermore, the lack of clear language in the code has led to enforcement uncertainty. While PHMSA is aware of guidance applicable to repair clamps, such as ASTM F1025, PHMSA is not aware of technical standards for permanent repair clamps on plastic pipe. Section 192.311 does not preclude the use of electrofusion repair sleeves, but for the sake of clarity, PHMSA has revised § 192.720 to specify that a "mechanical leak repair clamp" may not be used as a permanent repair. PHMSA may revisit this issue if an acceptable standard for permanent mechanical repair clamps on plastic pipe is developed. In general, if a repair device such as an electrofusion sleeve can provide a Category 1 joint, it is effectively permanent. Like other provisions of this final rule, the prohibition of the permanent use of leak repair clamps is not retroactive.

I. General Provisions

In the NPRM, PHMSA proposed several general revisions to the PSR as follows:

(1) Incorporation by Reference

(a) PHMSA's Proposal

PHMSA proposed to incorporate by reference several new or revised standards for plastic pipe and components. Summaries of each of the standards incorporated by reference in this final rule, and a discussion of the availability of those standards during the rulemaking process, are available in Part IV, *Standards Incorporated by Reference,* in the preamble to this document. Additionally, the effects of these standards are discussed under the topic area to which they are applicable. Section II, *Availability of Standards Incorporated by Reference,* of the NPRM preamble provided information on the reasonable availability of these standards.

(b) Summary of Comments

NAPSR supported PHMSA's proposal to incorporate by reference new standards and currently referenced consensus standards. Several commenters suggested incorporating more recent editions of certain standards that this rule incorporates by reference. Aaron Adamczyk provided a list of standards proposed in the NPRM that have since been updated by the respective standards development organization. Volgstadt and Associates and Arkema also noted that there were upcoming revisions to certain standards that could impact the NPRM.

GPA and TPA submitted comments arguing that the standards incorporated by reference in the NPRM are intended for distribution systems and that applying them to gas transmission and gathering lines would be improper. The commenters suggested that PHMSA restrict the scope of these standards to distribution lines and pursue a separate rulemaking to incorporate applicable standards for transmission and gathering lines.

PublicResource.org submitted a comment claiming that PHMSA had acted improperly at the NPRM stage by not making the standards proposed for incorporation by reference into the PSR available to the public for free, on the internet, on an unrestricted and permanent basis, as required by law.

(c) PHMSA's Response

As for the recommendation that PHMSA incorporate by reference more recent versions of the consensus standards, PHMSA can only incorporate by reference versions of standards that have been proposed at the NPRM stage of the rulemaking process. For this rulemaking, PHMSA contacted the applicable Standards Development Organizations (SDO), requesting that each SDO provides access to the standards proposed for incorporation by reference during the comment period. During this period, all standards proposed for incorporation by reference were made available to the public for free.

PHMSA does not propose new editions or versions of standards at the final rule stage without an opportunity for public comment. However, PHMSA may consider more recent versions for incorporation by reference in future rulemaking actions if the newer editions of these standards are technically acceptable and consistent with applicable law.

PHMSA does not agree with the comments that suggested limiting the applicability of certain materials standards to distribution facilities. While the scope of some of the plastic pipe standards incorporated by reference in this final rule may have been developed primarily for gas mains and service lines, there is nothing that precludes their use in gathering and transmission systems, as long as all appropriate testing and other considerations are met (*e.g.,* chemical compatibility testing.) In fact, PHMSA is aware of many gathering and transmission systems that are already using ASTM D2513 pipe. To avoid confusion, several SDOs are in the process of expanding the scope of these standards. PHMSA is also aware of other standards, either recently published or still under development, specific to transmission or gathering systems; however, for the time being, pipeline facilities must be constructed in accordance with standards incorporated by reference. PHMSA may, if appropriate, update standards with those clarifications or incorporate by reference transmission and gathering-specific standards in future rulemakings.

PHMSA also disagrees with the comment that incorporating only parts of consensus standards by reference is inconsistent with the intent of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113. Section 12(d) of NTTAA directs Federal agencies to use standards developed by voluntary consensus standards bodies in lieu of government standards whenever it is practical and consistent with law. The Office of Management and Budget (OMB) issued OMB Circular A–119 to serve as guidance to Federal agencies on the use of such standards. Specifically, OMB Circular A–119 explains the term "use" to mean "incorporation of a standard in whole, in part, or by reference in regulation(s)." OMB Circular A–119, at p. 20. OMB Circular A–119 also provides a list of factors that an agency should consider when evaluating whether to use a standard, which includes the level of protection a standard provides, the costs and benefits of implementing a standard, and the ability of the agency to use and enforce compliance with a standard in the regulatory process. *Id.,* at p. 17–18.

Neither NTAA nor OMB Circular A–119 establishes a requirement for Federal agencies to incorporate such standards in whole or to adopt the most recent edition of standards. Further, pursuant to 49 U.S.C. 60102(b)(1), standards adopted by PHMSA must be practicable and designed to meet the need for gas pipeline safety and protecting the environment. Accordingly, PHMSA may not adopt standards and portions of standards that fail either to serve its safety-program needs or it deems to be impracticable.

PHMSA also disagrees with comments from *Public Resource.Org* suggesting that PHMSA has failed to make standards incorporated by reference "reasonably available" and that it acted illegally and arbitrarily by proposing the incorporation of standards that were not neither reprinted verbatim in the **Federal Register** nor made available to the public for free, on the internet, on a permanent and unrestricted basis.

PHMSA supports the broad dissemination and public availability of consensus standards that have been incorporated by reference into federal regulations and that govern pipeline safety in this country. First, it complies with the procedures set by the Office of the Federal Register to ensure the reasonable availability of standards proposed for incorporation by reference in the rulemaking process. As *Public Resource.Org* noted in its comment, PHMSA worked with SDOs to provide free, read-only access to all standards proposed for incorporation by reference during the comment period. Providing free, read-only access to standards proposed for incorporation by reference during the comment period is listed under section 5(f) of OMB Circular A–119 (revised, 2016) as a measure that Federal agencies can take to ensure that such standards are made "reasonably available." Additionally, PHMSA has worked to make these materials reasonably available to interested parties. Section IV, "Standards Incorporation by Reference", of this final rule provides information on how interested parties can view the standards to be incorporated by reference online or via hardcopy at U.S. DOT headquarters and the Office of the Federal Register. This free online availability, which PHMSA also provided during the comment period, meets PHMSA's statutory requirements at 49 U.S.C. 60102(p), requiring that such standards incorporated by reference be made available to the public, free of charge.

Public Resource.Org has not provided sufficient evidence to support its interpretation that "reasonably available" requires Federal agencies, such as PHMSA, to provide internet access to copyrighted standards on a permanent and unrestricted basis free of charge. PHMSA therefore defers to the interpretation set forth in OMB Circular A–119. Broader questions raised by *Public Resource.Org* regarding the applicability of copyright law to standards, what constitutes fair use of standards incorporated by reference, and the economics of copyright protection are all beyond the scope of this rulemaking.

(2) Plastic Pipe Material

(a) PHMSA's Proposal

The NPRM proposed several revisions regarding material requirements for plastic pipe. PHMSA proposed to revise § 192.59 to require that new plastic pipe be free from visible defects and permit the installation of plastic pipe that had been previously used in "gas" service, as defined in § 192.3, rather than the current language, which is restricted to "natural gas." PHMSA also proposed to prohibit the installation of PVC pipe and components for new installations after the effective date of the rule and proposed to incorporate ASTM F2817–10, "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair," issued on February 1, 2010 (ASTM F2817–10), "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (PVC components only) 02/01/2010 (ASTM F2817–10), to reestablish standards for PVC components that are still permitted on existing PVC pipe segments.

(b) Summary of Comments

APGA and NAPSR supported PHMSA's proposal to prohibit the installation of new PVC gas piping. NAPSR stated that it "feels the exclusion of PVC pipe for new installations will increase safety."

The PVC Pipe Association, a trade group representing PVC pipe manufacturers, submitted comments opposed to PHMSA's proposal to prohibit new installation of PVC pipe in gas service. The PVC Pipe Association argued that prohibiting PVC pipe would restrict competition in the plastic piping sector with negative impacts on price and innovation. The PVC Pipe Association proposed permitting PVC pipe in low-diameter, SDR–11 applications. NiSource noted that PVC pipe could be effectively used as regulator and vent piping, arguing that prohibiting new PVC gas piping in these applications would increase pipeline risk by leading to increased use of metal pipe, which carries a corrosion risk. NiSource proposed adopting ANSI/UL 651, "Standard for Schedule 40, 80, Type EB and A Rigid PVC Conduit and Fittings, for rigid PVC conduits and fittings as permitted in NFPA 54, "National Fuel Gas Code." The GPAC recommended removing the PVC restrictions.

(c) PHMSA's Response

PHMSA has removed the restrictions on PVC pipe after considering the public comments and the recommendations of the GPAC. PHMSA notes that the use of PVC pipe has decreased since the mid-1980s without regulatory intervention due, in large part, to operator preferences. Gas distribution annual reports also show operators are phasing-out this material in the absence of a regulatory restriction.

(3) Plastic Pipe Storage and Handling

(a) PHMSA's Proposal

The NPRM proposed adding a new § 192.67 that would require operators to have written procedures for the storage and handling of plastic pipe that met applicable listed specifications.

(b) Summary of Comments

NAPSR and APGA supported the proposed amendments. APGA agreed "that proper storage and handling of plastic pipe and components is important to ensure that these pipe and components are not damaged during storage and handling." However, APGA sought clarification as to whether a simple, generic storage and handling procedure provided by the pipe and component manufacturer, trade association or another central source would satisfy the requirement.

AGA requested background information on PHMSA's addition of § 192.67, which AGA stated may be due to the adoption of ASTM D2513–09a.

(c) PHMSA's Response

Most commenters supported the addition of this section. In the final rule, PHMSA is issuing these provisions as proposed. In response to AGA's comment, PHMSA developed this requirement due to unsafe handling practices observed by PHMSA inspectors in the field. For example, PHMSA has observed operators dragging plastic pipe with backhoes and other heavy machinery, carrying pipe suspended from chains, and carrying large-diameter pipes with thin straps. In response to APGA's comment, PHMSA notes that operators may use procedures provided by a trade association, the pipe manufacturer, or another central source, provided that those procedures meet the minimum requirements specified in the code and applicable listed specifications and are included in the operator's operations and maintenance manual.

(4) Gathering Lines

(a) PHMSA's Proposal

The NPRM proposed adding language in paragraph § 192.9(d) to specify that Type B regulated onshore gas gathering pipelines made of plastic must comply with all the requirements of part 192 applicable to plastic pipe.

(b) Summary of Comments

NAPSR and DTE submitted comments supporting PHMSA's proposal. However, DTE commented that PHMSA may have inadvertently omitted the leakage survey requirements for Type B gathering lines already in § 192.9(d)(7). DTE suggested placing the new requirements for plastic pipe and components in a more logical order in § 192.9(d).

(c) PHMSA's Response

As commenters noted, PHMSA's intent was not to repeal the recently promulgated leakage survey requirements in what was previously § 192.9(d)(7). In this final rule, PHMSA has therefore reorganized this section as recommended by the commenters and re-designated the leakage survey requirement as § 192.9(d)(8).

(5) Merger of Sections 192.121 and 192.123

(a) PHMSA's Proposal

The NPRM proposed merging the design limitations for plastic pipe in § 192.123 with the calculations for design pressure at § 192.121 so the design pressure and limitations were in one section and more clearly broken out by material type. PHMSA also proposed to revise the PSR to raise the maximum permitted design factor for PE pipe, increase the design pressure limitations of PA–11 pipe, and add design factor and pressure limitations for the use of PA–12 plastic pipe. These requirements would apply to materials produced after the effective date of the rule.

(b) Summary of Comments

Arkema and Palermo recommended that PHMSA allow the installation of plastic pipe designed with a hydrostatic design basis (HDB) at 180 °F, in addition to 73 °F, 100 °F, 120 °F and 140 °F currently in the regulations. The commenters noted that PA–11 and other materials (including PA–12) have an HDB with a rating of 180 °F, so it should be listed along with the other standard temperatures. As described in the sections for PE, PA–11, and PA–12 provision, a number of commenters suggested expansions and revisions to the minimum wall thickness tables in § 192.121 for each material to include entries for pipe with nominal pipe sizes of one-inch CTS and below one-inch IPS.

(c) PHMSA's Response

The comments filed under this subsection primarily concern revisions to the PE, PA–11, and PA–12 tables and HDB temperature ratings for PA–11 and PA–12. As described in the discussions of those topics, PHMSA is revising the minimum wall thickness tables for clarity and to include additional sizes but is not permitting the installation or operation of pipe at temperatures higher than 140 °F. As noted in the discussions for PE, PA–11, and PA–12, not all compounds are rated at that temperature, and inclusion could wrongly imply that operators are permitted to operate any plastic pipe at that temperature. This doesn't preclude an operator from using a pipe with an HDB rating at 180 °F, however, that rating would need to be interpolated back to one of the temperatures listed in § 192.121. See the discussions of the PE, PA–11, and PA–12 provisions in sections III.B, III.C, and III.D of the preamble of this final rule for more detailed information on these subjects. PHMSA also notes this particular consideration for pipe rated at higher temperatures is already in § 192.121, which allows an operator to use an HDB of a higher temperature when using arithmetic interpolation using procedures called out in Part D.2 of PPI TR–3, (incorporated by reference, *see* § 192.7).

(6) General Design Requirements for Components

(a) PHMSA's Proposal

The NPRM proposed adding a new paragraph (c) to § 192.143 to specify that components used for plastic pipe must be able to withstand the operating pressures and anticipated loads in accordance with a listed specification. This revision makes § 192.191 redundant as the requirements for fittings to meet listed specifications are detailed in other parts of the code; therefore, PHMSA proposed to eliminate § 192.191.

(b) Summary of Comments

NAPSR supported the proposal but suggested revising § 192.143 to include the language, "in accordance with the listed specification for the plastic component being installed." NAPSR commented that this wording would provide additional clarification.

NiSource and R.W. Lyall expressed concern that, as written, the proposal would require excess flow valves (EFVs) to meet a listed specification. However an EFV specification has not yet been incorporated. The commenters suggested that PHMSA either exempt EFVs from the specification requirement or incorporate by reference an EFV specification such as ASTM F2138, "Standard Specification for Excess Flow Valves for Natural Gas Service" (ASTM F2138).

(c) PHMSA's Response

PHMSA appreciates NAPSR's desire to clarify the applicability of certain standards, but, after careful consideration, PHMSA believes the existing language and the referenced standards are sufficiently clear for operators to know to use the standard for the appropriate component type and material. Therefore, PHMSA is not making further changes to this requirement in this final rule.

Regarding EFVs, PHMSA did not intend to create conflict with EFV requirements. PHMSA has therefore revised the final rule to exempt EFVs from the requirement to meet a listed specification since there is not one specifically listed in Appendix B to part 192. PHMSA will consider incorporating appropriate standards, such as ASTM F2138, in the future.

(7) General Design Requirements for Valves

(a) PHMSA's Proposal

PHMSA proposed adding a new § 192.145(f) to specify that valves on plastic pipe must meet a "listed specification" as defined in § 192.3. In other words, valves must be manufactured in accordance with the appropriate consensus standard incorporated by reference into § 192.7. PHMSA also proposed that plastic valves must not be used under operating conditions that exceed the applicable temperature or temperature ratings detailed in the listed specification and consistent with § 192.145(a).

(b) Summary of Comments

AGA and TPA requested that the language in § 192.145(f) be revised to clarify that the requirements for new valves do not apply retroactively.

NAPSR suggested revising the specification requirement to require that valves meet the listed specification for the particular valve being installed.

(c) PHMSA's Response

PHMSA notes that the requirements in § 192.145 do not apply retroactively. PHMSA appreciates NAPSR's desire to clarify the applicability of certain standards; however, the agency believes the existing language and the referenced standards are sufficiently clear for operators to know to use the appropriate standard for the valve type and material being installed. Therefore, PHMSA is not making further changes to this requirement in this final rule.

(8) General Design Requirements for Standard Fittings

(a) PHMSA's Proposal

PHMSA proposed adding § 192.149(c) to clarify that a plastic pipe fitting may only be used if it meets a listed specification. This ensures that standard fittings meet minimum technical standards detailed in industry consensus standards.

(b) Summary of Comments

NAPSR supported the proposal but suggested revising the language to require components to meet the listed specification for the specific part being installed.

Volgstadt and Associates suggested incorporating ASTM D3261 for PE butt-fusion fittings and ASTM D2683 for PE socket-fusion fittings.

(c) PHMSA's Response

In this final rule, PHMSA is issuing this section as originally proposed. As with the previous section, PHMSA has determined that the language of this requirement is sufficiently clear with the existing wording. Regarding the additional standards proposed, PHMSA cannot incorporate additional standards in the final rule stage that were not proposed and commented on in the NPRM stage. However, PHMSA will consider incorporating applicable standards in future rulemakings.

(9) Test Requirements for Plastic Pipelines

(a) PHMSA's Proposal

The NPRM proposed revising § 192.513(c) to reduce the maximum test-pressure limit for plastic pipe to from 3.0 to 2.5 times the pressure determined under § 192.121. Given the other design limitations in the current § 192.123 for PE and PA–11, and the revisions being proposed in this rule for PE, PA–11, and PA–12, PHMSA believes that plastic pipe will potentially be overstressed if tested to 3 times the pressure determined under § 192.121.

(b) Summary of Comments

NAPSR and Arkema submitted comments supporting the proposed changes.

(c) PHMSA's Response

PHMSA did not receive comments critical of this proposal. Therefore, the final rule incorporates this requirement as originally proposed.

IV. Standards Incorporated by Reference

A. Summary of New and Revised Standards

Consistent with the amendments in this document, PHMSA is incorporating by reference several standards as described in more detail below. Some of these standards are simply updates to existing standards that are already incorporated by reference, while others provide a technical basis for corresponding regulatory changes in the Final Rule, notably the provisions related to PA–11 and PA–12 piping systems.

• ASTM D2513–12ael "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings," 4/12/2012. This specification covers requirements and test methods for material dimensions and tolerances; hydrostatic burst strength; chemical resistance; and rapid crack resistance of polyethylene pipe, tubing, and fittings for use in fuel gas mains and services for direct burial and reliner applications. The pipe and fittings covered by this specification are for use in the distribution of natural gas. Requirements for the qualifying of polyethylene systems for use with liquefied petroleum gas are also covered.

This standard is an update to standard ASTM D2513–09a (12/1/2009), which is currently incorporated by reference in the CFR. The updated version of this standard adds ASTM F2897 "Specification for Tracking and Traceability Encoding System of Natural Gas Distribution Components (Pipe, Tubing, Fittings, Valves, and Appurtenances)" to its referenced document list in Section 2. There is also a new Section 7.6 to address additional marking requirements for incorporating the 16-character code onto PE Pipe and Fittings. The standard also now limits pipe material designation codes to PE 2708 and PE4710 to be consistent with PHMSA DOT Part 192.

• ASTM F2785–12 "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings," 8/1/2012. This specification covers requirements and test methods for the characterization of PA–12 pipe, tubing, and fittings for use in fuel gas mains and services for direct burial and reliner applications. The pipe and fittings covered by this specification are for use in the distribution of natural gas. No version of this specification is currently in the CFR.

The final rule will permit the use of PA–12 plastic pipe, which is not permitted under existing regulations. In order to facilitate this change, PA–12 pipe and fittings will need to follow a listed specification, and reference to commonly used industry standards (ASTM F2785) is a preferred approach. Adding dedicated and material specific standards for both PA–11 and PA–12 will also allow PHMSA to remove two much older versions of ASTM D2513 (ASTM D2513–87 and ASTM D2513–99) that are currently referenced for thermoplastic materials other than PE. Overall, this change gives operators additional flexibility in choice of material.

• ASTM F2945–12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings," 11/27/2012. This specification covers requirements and test methods for the characterization of PA–11 pipe, tubing, and fittings for use in fuel gas piping. No version of this specification is currently in the CFR.

The final rule will expand operators' ability to use PA–11 plastic pipe. PA–11 is currently allowed but with certain limitations on pressure and dimensions. The rule will also update regulations to align with more current industry standards for PA–11 (*i.e.* the ASTM F2945 standard). Adding dedicated and newer material specific standards for both PA–11 and PA–12 will also allow PHMSA to remove two much older versions of ASTM D2513 (ASTM D2513–87 and ASTM D2513–99) that are currently referenced for thermoplastic materials other than PE. Overall, these changes give operators additional flexibility in choice of material.

• ASTM F2620–12 "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings," 8/01/2013. This practice describes procedures for making joints with PE pipe and fittings by means of heat-fusion joining in, but not limited to, a field environment. The parameters and procedures are applicable only to joining PE pipe and fittings of related polymer chemistry. No version of this standard is currently in the CFR.

The final rule includes a new provision related to heat fusion joints for PE pipe, stating that these must comply with the relevant standard (ASTM F2620–12). Although some comments were received objecting to this change, these were either based on a misunderstanding of the proposal or of the standard itself, as discussed in the comment summary above. PHMSA believes that this will help address gaps and inconsistencies in joining procedures.

• ASTM D2564–12 "Standard Specification for Solvent Cements for Poly (Vinyl Chloride) (PVC) Plastic Piping Systems" 08/01/2012. This specification covers requirements for solvent cements used in joining PVC piping systems.

The final rule includes a minor correction updating and providing a more direct reference to the technical standard for solvent cements and noting that the requirements in this standard apply only to PVC pipe. ASTM D2564 had been a referenced document in the previous versions of ASTM D2513 that applied to all thermoplastics, which in turn was incorporated by reference into PHMSA regulation. With the removal of ASTM D2513–99 and ASTM D2513–99 that is currently referenced for all thermoplastics other than PE, standards need to be included to apply to PVC piping systems that are still in use today (although typically for maintenance or repair only). In addition to referencing ASTM F2817–10 for Maintenance and Repair of PVC, PHMSA believes it is important to reference this standard for the specific solvent to be used. Even with it being included as a referenced document within the standard previously, PHMSA and States have found cases occasionally where non-listed solvents were used contributing to improper joints.

• ASTM F1924–12, "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing," 4/01/2012. This specification describes test methods and material requirements for plastic mechanical fittings for use with outside diameter-controlled PE gas distribution pipe smaller than 2-inch IPS. No version of this specification is currently in the CFR.

The final rule revises the regulations for mechanical joints and fittings by adding requirements for seal plus pullout resistance and citing the relevant industry standard(s). The allowable fittings are already widely in use and have little to no cost difference from other fittings for either labor or materials. This item would be added as a Listed Specification in Appendix B to Part 192-Qualification of Pipe and Components.

• ASTM F2817–10 "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair," (PVC components only) 02/01/2010. This specification covers requirements for PVC pipe and tubing for use only to maintain or repair existing PVC gas piping. No version of this specification is currently in the CFR.

This item would be added as a Listed Specification in Appendix B to Part 192-Qualification of Pipe and Components. With the removal of ASTM D2513–99 and ASTM D2513–99 that is currently referenced for all thermoplastics other than PE, standards need to be included to apply to PVC piping systems that are still in use today (although typically for maintenance or repair only).

• ASTM F 2600–09 "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing," 4/1/2009. This specification covers PA–11 electrofusion fittings for use with outside-diameter controlled PA–11 pipe covered by Specification D2513. Requirements for materials, workmanship, and testing performance are included. No version of this specification is currently in the CFR.

This item would be added as a Listed Specification in Appendix B to Part 192-Qualification of Pipe and Components. With new material specific standards being added for PA–11 and other standards being added for components in this rule, there is a need to add F2600 for Electrofusion PA–11 fittings, similar to how ASTM F1055 is currently referenced for PE Electrofusion Fittings.

• ASTM F2767–12 "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution" 10/15/2012.—This specification applies to PA–12 electrofusion fittings for use with outside diameter-controlled PA–12 pipes addressed by Specification F2785. No version of this specification is currently in the CFR.

This item would be added as a Listed Specification in Appendix B to Part 192-Qualification of Pipe and Components. With new material, specific standards being added for PA–12 and other standards being added for components in this rule, there is a need to add F2767 for Electrofusion PA–12 fittings, similar to how ASTM F1055 is currently referenced for PE Electrofusion Fittings.

• ASTM F2145–13 "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing," 05/01/2013. This specification describes requirements and test methods for the qualification of PA–11 and PA–12 bodied mechanical fittings for use with outside diameter-controlled PA–11 and PA–12, with 2-inch-and-smaller IPS complying with Specification D2513 and F2785. In addition, it specifies general requirements of the material from which these fittings are made. No version of this specification is currently in the CFR.

This item would be added as a Listed Specification in Appendix B to Part 192-Qualification of Pipe and Components. With new material specific standards being added for PA–11 and PA–12 and other standards being added for components in this rule, there is a need to add F2145 for PA–11 and PA–12 mechanical fittings.

• ASTM F1948–12 "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing," 04/01/2012. This specification covers requirements and test methods for the qualification of metallic mechanical fittings for use with outside diameter-controlled thermoplastic gas distribution pipe and tubing as specified in Specification D2513. No version of this specification is currently in the CFR.

The final rule revises the regulations for mechanical joints and fittings by adding requirements for seal plus pullout resistance and citing the relevant industry standard(s). The allowable fittings are already widely in use.

This item would be added as a Listed Specification in Appendix B to Part 192-Qualification of Pipe and Components. With new material specific standards being added and other standards being added for components in this rule, there is a need to add F1948 for metallic mechanical fittings on thermoplastic pipe. This standard would apply to metallic fittings used on multiple types of thermoplastic pipe (*i.e.* PE, PA–11 and PA–12).

• ASTM F1973–13 "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems," 05/01/2013. This specification covers requirements and test methods for the qualification of factory assembled anodeless risers and transition fittings for use in PE pipe sizes through Nominal Pipe Size (NPS) 8, and for PA–11 and PA–12 sizes through NPS 6. No version of this standard is currently in the CFR.

The final rule uses this standard to establish the procedures for designing and testing factory assembled anodeless risers. The standard also provides a definition for Category 1 fittings on plastic pipe. This item would be added as a Listed Specification in Appendix B to Part 192-Qualification of Pipe and Components.

• ASME B16.40–08 "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems," 03/18/2008. This standard defines design qualification requirements for manually operated thermoplastic valves in nominal valve sized from ½- through 12 inches that are intended for use below ground in thermoplastic fuel gas distribution mains and service lines. No version of this standard is currently in the CFR.

This item would be added as a Listed Specification in Appendix B to Part 192-Qualification of Pipe and Components. This standard is included based on a petition to include thermoplastic valves.

• PPI TR–4, HDB/HDS/SDB/MRS, Listed Materials, "PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Rating For Thermoplastic Piping Materials or Pipe," updated March, 2011. This report lists thermoplastic piping materials with a PPI recommended HDB, Strength Design Basis (SDB), Pressure Design Basis (PDB), or Minimum Required Strength (MRS) rating for thermoplastic piping materials or pipe. These listings have been established in accordance with PPI TR–3. No version of this listing is currently in the CFR directly, although PPI TR–4 has been incorporated indirectly through PPI TR–3 and other requirements for determining design pressure for pipe.

The final rule requires that all plastic pipe, when designed, must have a listed Hydrostatic Design Basis (HDB) rating in accordance with this standard.

PHMSA also updated the following standards, which are summarized below:

• ASTM F1055–98 (reapproved 2006) "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing," 3/1/2006. This specification covers electrofusion polyethylene fittings for use with outside diameter-controlled polyethylene pipe covered by Specifications D2447, D 2513, D2737, D3035, and F714. This specification is a 2006 reaffirmed version of the 1998 version, meaning the technical content of the standard hasn't changed, but the ASTM technical committee procedurally reviewed it to keep it active.

With the changes being made to the regulations and other component specifications for other materials such as PA–11 and PA–12 being added, the language in 192.283(a) that previously only mentioned F1055 for PE is being revised. Along with the applicable component specifications for other material types, this item would be added as a Listed Specification in Appendix B to Part 192-Qualification of Pipe and Components.

• PPI TR–3/2012, HDB/HDS/PDB/SDB/MRS/CRS, Policies, "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis (SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe," updated November 2012. This report presents the policies and procedures used by the HSB (Hydrostatic Stress Board) of PPI to develop recommendations of long-term strength ratings for commercial thermoplastic piping materials or pipe. This version is an update to the 2008 version currently incorporated by reference. A more detailed summary of updates to the 2010 version (successor to the 2008 version) is available in the 2012 document itself. Recommendations are published in PPI TR–4. Both documents are freely available on the internet as of the date of publication of this final rule.

The final rule describes the standard as a procedure that can be used to determine a design pressure rating. This is an updated version of the standard currently referenced in the regulations.

B. 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 SDOs. In general, SDOs update and revise their published standards every two to five years to reflect modern technology and best technical practices. ASTM often updates some of its more widely used standards every year. Sometimes multiple editions are published in a given year.

In accordance with the NTTAA, 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 49 CFR parts 192, 193, and 195. Revisions to incorporated by reference materials in parts 192, 193, and 195 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.

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Public Law 112–90. Section 24 of that law states: "Beginning 1 year after the date of enactment of this subsection, the Secretary may not issue guidance or a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge, on an internet website." 49 U.S.C. 60102(p).

On August 9, 2013, Public Law 113–30 revised 49 U.S.C. 60102(p) to replace "1 year" with "3 years" and remove the phrases "guidance or" and, "on an internet website." This resulted in the current language in 49 U.S.C. 60102(p), which now reads as follows:

> Beginning 3 years after the date of enactment of this subsection, the Secretary may not issue a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge.

On November 7, 2014, the Office of the Federal Register issued a final rule that revised 1 CFR 51.5 to require that Federal agencies include a discussion in the preamble of the final rule "the ways the materials it incorporates by reference are reasonably available to interested parties and how interested parties can obtain the materials." 79 FR 66278. To meet its statutory obligation for this final rule, PHMSA negotiated an agreement with ASTM to provide viewable copies of standards incorporated by reference in the PSR available to the public at no cost. The Plastics Pipe Institute provides free electronic copies of their standards on their website (*http://plasticpipe.org/publications/technical-reports.html*). Each organization's mailing address and the website are listed in § 192.7.

In addition, PHMSA will provide individual members of the public temporary access to any standard that is incorporated by reference that is not otherwise available for free. This includes the one ASME standard described in the previous paragraph. Requests for access can be sent to the following email address: *PHMSAPHPStandards@dot.gov*

V. Regulatory Analysis and Notices

Summary/Legal Authority for This Rulemaking

This final rule is published under the authority of the Federal pipeline safety statutes. 49 U.S.C. 60101 *et seq.* Section 60102 authorizes the Secretary of Transportation to issue regulations governing the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of 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 PSR. This final rule will modify the PSR applicable to plastic pipe used in the transportation of gas.

Executive Order 12866, Executive Order 13563, Executive Order 13771, and DOT Regulatory Policies and Procedures

This final rule is a significant regulatory action under Executive Order 12866, 58 FR 51735, and the Regulatory Policies and Procedures of the Department of Transportation. The rule was therefore reviewed by the Office of Management and Budget. A Regulatory Impact Analysis with estimates of the costs and benefits of the final rule is available in the docket. Executive Order 12866, as supplemented by Executive Order 13563, 76 FR 3821, requires agencies to regulate in the "most cost-effective manner," to make a "reasoned determination that the benefits of the intended regulation justify its costs," and to develop regulations that "impose the least burden on society." PHMSA is amending the PSR with regard to plastic pipe to improve compliance with these regulations by updating and adding references to technical standards and providing clarification. PHMSA anticipates that the amendments contained in this final rule will have net economic benefits to the public. The final rule enhances safety, reduces costs for the regulated community, improves regulatory clarity, increases ease of compliance, and provides additional flexibility in gas pipeline material choices. A copy of the regulatory evaluation is available for review in the docket.

This final rule is considered an E.O. 13771 deregulatory action. Details on the estimated cost savings of this rule can be found in the rule's economic analysis.

Regulatory Flexibility Act

The Regulatory Flexibility Act requires an agency to review regulations to assess their impact on small entities unless the agency determines that a rule is not expected to have a significant impact on a substantial number of small entities. 5 U.S.C. 601 *et seq.* This final rule has been developed in accordance with Executive Order 13272, "Proper Consideration of Small Entities in Agency Rulemaking," 67 FR 53461, and DOT's procedures and policies to promote compliance with the Regulatory Flexibility Act to ensure that potential impacts of rules on small entities are properly considered.

While PHMSA does not collect information on the number of employees or revenues of pipeline operators, it does continuously seek information on the number of small pipeline operators to more fully determine any impacts PHMSA's proposed regulations may have on small entities. This final rule proposes to require small and large operators to comply with these requirements. Based on the results of PHMSA's Final Regulatory Flexibility Analysis, PHMSA has determined that the final rule will not have a significant economic impact on a substantial number of small entities. The final Regulatory Flexibility Act Analysis is included in the Regulatory Impact Analysis, available via *regulations.gov.*

Executive Order 13175

PHMSA has analyzed this final rule according to the principles and criteria in Executive Order 13175, "Consultation and Coordination with Indian Tribal Governments," 65 FR 67249. Because this final rule does not significantly or uniquely affect the communities of the Indian tribal governments or impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

Paperwork Reduction Act

PHMSA has analyzed this final rule in accordance with the Paperwork Reduction Act of 1995 (PRA). Public Law 96–511. The PRA requires federal agencies to minimize paperwork burden imposed on the American public by ensuring maximum utility and quality of Federal information, ensuring the use of information technology to improve Government performance and improving the Federal government's accountability for managing information collection activities. This final rule does not impose any new information collection requirements.

Unfunded Mandates Reform Act of 1995

This final rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. Public Law 104–4. It 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, and is the least burdensome alternative that achieves the objective of the final rule.

National Environmental Policy Act

PHMSA analyzed this final rule in accordance with section 102(2)(c) of the National Environmental Policy Act, 42 U.S.C. 4332, the Council on Environmental Quality regulations, 40 CFR parts 1500–1508, and U.S. DOT Order 5610.1C, and has determined that this action will not significantly affect the quality of the human environment. An environmental assessment of this rulemaking is available in the docket.

Privacy Act Statement

Anyone can search the electronic form of written communications and comments received into our dockets by the name of the individual submitting the document (or signing the document, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement, published on April 11, 2000 (65 FR 19476), in the **Federal Register** at: *https://www.gpo.gov/fdsys/pkg/FR-2000-04-11/pdf/00-8505.pdf.*

Executive Order 13132

PHMSA has analyzed this final rule according to Executive Order 13132, "Federalism," 64 FR 43255. The final rule does not have a substantial direct effect on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government. This final rule does not impose substantial direct compliance costs on State and local governments. This final rule does not preempt State law for intrastate pipelines. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply *Executive Order 13211.*

This final rule is not a "significant energy action" under Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use," 66 FR 28355. It is not likely to have a significant adverse effect on energy supply, distribution, or use. Further, the Office of Information and Regulatory Affairs has not designated this final rule as a significant energy action.

Regulation Identifier Number

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 contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

VI. Section-by-Section Analysis

Section 192.3 Definitions

Section 192.3 provides definitions for various terms used throughout part 192. In support of other provisions in this final rule, PHMSA has added a definition for "weak link" that outlines methods used to avoid overstressing plastic pipe during trenchless excavation.

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

Section 192.7 contains a list of all standards incorporated by reference in part 192. This final rule adds or updates a number of standards related to plastic pipe, fittings, and other components made of PE, PA–11, and PA–12. PHMSA is also adding a standard for maintenance or repair of PVC segments.

Section 192.9 What requirements apply to gathering lines?

Section 192.9 identifies those portions of part 192 that apply to regulated gas gathering lines. PHMSA amended this section by adding a new paragraph (d)(3) to specify that newly constructed

Type B regulated gas gathering pipelines made of plastic must comply with all requirements of part 192 applicable to plastic pipe. The previously existing language in paragraphs (d)(3)–(d)(7) have remained the same, but have been reordered to paragraphs (d)(4)–(d)(8) in this final rule.

Section 192.59 Plastic Pipe

Section 192.59 specifies requirements for plastic pipe materials. This final rule amends this section by requiring operators to verify that all pipe is free of visible defects prior to installation and permit the use of pipe that had been previously used in gas service other than natural gas.

Section 192.63 Marking of Materials

Section 192.63 currently specifies requirements for the type and content of markings of pipe segments, valves, and fittings. In this final rule, PHMSA revises paragraph (a) to delete paragraphs (a)(1) and (a)(2). The revised paragraph (a) requires that materials be marked in accordance with the appropriate listed specification.

Section 192.67 Storage and Handling of Plastic Pipelines

The newly added § 192.67 establishes storage and handling standards for plastic pipeline components.

Section 192.121 Design of Plastic Pipe

Section 192.121 has been amended to specify the design requirements for newly installed plastic tubing made of PE, PA–11, and PA–12. In response to petitions, PHMSA has revised the maximum specifications for PE pipe and permitted the use of PA–12 in gas service. New and replaced PE pipe may now operate with a design factor of 0.40 (previously 0.32), though it is limited to a minimum wall thickness of 0.090 inches. New and replaced PA–11 pipe may now be operated with a design factor of 0.40, a maximum pressure up to 250 psig (previously 200) and a maximum diameter of 6 inches (previously 4). Operators are now permitted to install PA–12 with a design factor of 0.40, a maximum pressure up to 250 psig, and a maximum diameter of 6 inches. Finally, the design limitations which were previously located in § 192.123 have been merged into this section.

Section 192.123 [Removed and Reserved]

Section 192.123 previously contained design limitations for plastic pipe; however, this content has been merged into § 192.121.

Section 192.143 General Requirements

Section 192.143 contains general design provisions for pipeline components. For clarity, PHMSA added a new paragraph (c) to specify that components used for plastic pipe must be able to withstand operating pressures and anticipated loads in accordance with a listed specification, as defined in § 192.3.

Section 192.145 Valves

Section 192.143 contains general design provisions for pipeline valves. For clarity, PHMSA has added a new paragraph (f) to specify that plastic valves must be designed to meet a "listed specification" as defined in § 192.3 and not operated in conditions that exceed the applicable pressure or temperature ratings detailed in the applicable listed specification.

Section 192.149 Standard Fittings

Section 192.149 contains general design provisions for pipeline fittings. For clarity, PHMSA added a new paragraph (c) to specify that a plastic fitting may only be installed if it meets a listed specification, as defined in § 192.3.

Section 192.191 Design Pressure of Plastic Fittings [Removed and Reserved]

Section 192.191 is now redundant with the addition of § 192.143(c) and has been removed and reserved.

Section 192.204 Risers

Section 192.204 is new and establishes requirements for the design and construction of risers. PHMSA now requires all riser designs to be tested to ensure safe performance under anticipated external and internal loads. This section also requires factory assembled anodeless risers to be designed and tested in accordance with ASTM F1973 and allows the use of plastic risers from plastic mains to regulator stations with certain expectations and limitations.

Section 192.281 Plastic Pipe

Section 192.281 details the requirements for joining plastic pipe. To reduce confusion and promote safety, PHMSA is making several revisions to § 192.281. Paragraphs (b)(2) and (3) are revised to clarify that solvent cements may only be used to join PVC components and may not be heated or cooled to accelerate setting. Paragraph (c) is revised to specify that the joining requirements apply to both the pipe and components that are joined to the pipe, and for PE joints except for electrofusion must comply with ASTM F2620–12. Paragraphs (e)(3) and (4) are added to require that newly installed mechanical fittings must meet a listed specification and provide Category 1 seal and resistance.

Section 192.283 Plastic Pipe: Qualifying Joining Procedures

Section 192.283 details the requirements for qualifying plastic pipe joining procedures. PHMSA is incorporating requirements for mechanical joints or fittings to be Category 1. Since PHMSA is also incorporating new standards applicable to PE, PA–11 and PA–12 materials as part of this rule, this section is revised to remove references to two versions of ASTM D2513 (depending on whether it's PE or plastic materials other than PE) and instead require operators test procedures in accordance with the appropriate listed specification. PHMSA is also repealing the obsolete § 192.283(d), which allowed operators to install used pipe or fittings manufactured before July 1, 1980, if they are joined in accordance with procedures that the manufacturer certifies will produce a joint strong as the pipe.

Section 192.285 Plastic Pipe: Qualifying Persons To Make Joints

Section 192.285 details the requirements for qualifying persons to make joints. This final rule amends § 192.285 to incorporate several revisions. Section 192.285(a)(2) previously specified that a person must make a specimen joint that is subjected to the testing detailed in § 192.285(b). PHMSA referenced ASTM F2620–12 (Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings) applicable to PE pipe and fittings (except for electrofusion).

Section 192.313 Bends and Elbows

Section 192.313 details standards for bends and elbows in pipe, however, it did not previously address plastic pipe. This final rule adds a new paragraph (d) requiring that operators may only make bends in plastic pipe with a bend radius greater than the minimum bend radius specified by the manufacturer.

Section 192.321 Installation of Plastic Pipelines

Section 192.321 details requirements for the installation of plastic pipe transmission lines and mains. This final rule makes several amendments to this section. Paragraph (d) is revised to require newly installed plastic pipe have a wall thickness consistent with § 192.121. PHMSA has also revised paragraph (f) to specify that the plastic pipe must be protected from damage at both the entrance and exit of the casing during the installation process. Due to the merger of §§ 192.121 and 192.123, PHMSA has corrected § 192.321(h)(3) to refer to § 192.121. Finally, a new paragraph (i) has been added to allow for the aboveground termination of plastic mains under certain conditions.

Section 192.329 Installation of Plastic Pipelines by Trenchless Excavation

The newly added § 192.329 establishes requirements for the installation of plastic pipe by trenchless excavation. During trenchless installation of plastic pipe, operators must now use a weak link as defined in § 192.3 and take practicable steps to avoid striking other underground structures.

Section 192.367 Service Lines: General Requirements for Connections to Main Piping

Section 192.367 specifies requirements for service line connections to mains. Paragraph (b) specifies requirements for compression-type fittings for service-line main connections. Similar to the new requirements for other fittings, paragraph (b) is amended to require that operators must use Category 1 compression-type fittings.

Section 192.375 Service Lines: Plastic

Section 192.375 requires that plastic service lines be installed underground with limited exceptions. The final rule amends this section to apply the riser standards in § 192.204 to aboveground service lines.

Section 192.376 Installation of Plastic Service Lines by Trenchless Excavation

Section 192.376 is a new section that establishes new requirements for trenchless excavation installation of plastic service lines. Similar to § 192.329, during trenchless installation of service lines, operators must now take steps to avoid other underground structures and use a weak link device during the pull through process to avoid overstressing the pipeline.

Section 192.455 External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971

Section 192.455 details the external corrosion control requirements for all buried or submerged pipe. PHMSA has added a new paragraph (g) to require cathodic protection on electrically isolated metal fittings on plastic pipelines not meeting the exceptions in paragraph (f) installed after the effective date of the rule. Such fittings must also be maintained in accordance with the operator's integrity management plans.

Section 192.513 Test Requirements for Plastic Pipelines

Section 192.513 details the minimum initial testing requirements for plastic pipelines. The final rule amends paragraph (c) to reduce the maximum limit for testing pressure from 3 times the pressure determined under § 192.121 to 2.5 times the maximum pressure to avoid overstressing the line during testing.

Section 192.720 Distribution Systems: Leak Repair

The final rule adds a new § 192.720 prohibiting the use of temporary mechanical leak repair clamps as a permanent repair of plastic pipe used in distribution service.

Section 192.756 Joining Plastic Pipe by Heat Fusion; Equipment Maintenance

The final rule adds a new § 192.756 that establishes minimum requirements for equipment maintenance for equipment used in the heat fusion of plastic pipe.

List of Subjects in 49 CFR Part 192

Incorporation by reference, Pipeline safety, Plastic pipe, Security measures.

In consideration of the foregoing, PHMSA is amending 49 CFR part 192 as follows:

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

■ 1. The authority citation for part 192 is revised 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.

■ 2. In § 192.3, add a definition of "weak link" in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Weak link means a device or method used when pulling polyethylene pipe, typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stresses allowed.

* * * * *

■ 3. Amend § 192.7 as follows:

■ a. Redesignate paragraphs (c)(3) through (c)(9) as paragraphs (c)(4) through (c)(10);

■ b. Add new paragraph (c)(3);

■ c. Revise paragraphs (d)(11) through (d)(15);

■ d. Add paragraphs (d)(16) through (d)(24); and

■ e. Revise paragraph (j)(1) and add paragraph (j)(2).

The additions and revisions read as follows:

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

* * * * *

(c) * * *

(3) ASME B16.40–2008, "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems," March 18, 2008, approved by ANSI, (ASME B16.40–2008), IBR approved for Item I, Appendix B to Part 192.

* * * * *

(d) * * *

(11) ASTM D2513–12ae1, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings," April 1, 2012, (ASTM D2513–12ae1), IBR approved for Item I, Appendix B to Part 192.

(12) ASTM D2517–00, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings," (ASTM D 2517), IBR approved for §§ 192.191(a); 192.281(d); 192.283(a); and Item I, Appendix B to Part 192.

(13) ASTM D2564–12, "Standard Specification for Solvent Cements for Poly (Vinyl Chloride) (PVC) Plastic Piping Systems," Aug. 1, 2012, (ASTM D2564–12), IBR approved for § 192.281(b)(2).

(14) ASTM F1055–98 (Reapproved 2006), "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing," March 1, 2006, (ASTM F1055–98 (2006)), IBR approved for § 192.283(a), Item I, Appendix B to Part 192.

(15) ASTM F1924–12, "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing," April 1, 2012, (ASTM F1924–12), IBR approved for Item I, Appendix B to Part 192.

(16) ASTM F1948–12, "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing," April 1, 2012, (ASTM F1948–12), IBR approved for Item I, Appendix B to Part 192.

(17) ASTM F1973–13, "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems," May 1, 2013, (ASTM F1973–13), IBR approved for § 192.204(b); and Item I, Appendix B to Part 192.

(18) ASTM F2145–13, "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing," May 1, 2013, (ASTM F2145–13), IBR approved for Item I, Appendix B to Part 192.

(19) ASTM F 2600–09, "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide–11 Pipe and Tubing," April 1, 2009, (ASTM F 2600–09), IBR approved for Item I, Appendix B to Part 192.

(20) ASTM F2620–12, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings," Aug. 1, 2012, (ASTM F2620–12), IBR approved for §§ 192.281(c) and 192.285(b)(2)(i).

(21) ASTM F2767–12, "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide–12 Pipe and Tubing for Gas Distribution," Oct. 15, 2012, (ASTM F2767–12), IBR approved for Item I, Appendix B to Part 192.

(22) ASTM F2785–12, "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings," Aug. 1, 2012, (ASTM F2785–12), IBR approved for Item I, Appendix B to Part 192.

(23) ASTM F2817–10, "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair," Feb. 1, 2010, (ASTM F2817–10), IBR approved for Item I, Appendix B to Part 192.

(24) ASTM F2945–12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings," Nov. 27, 2012, (ASTM F2945–12a), IBR approved for Item I, Appendix B to Part 192.

* * * * *

(j) * * *

(1) PPI TR–3/2012, HDB/HDS/PDB/SDB/MRS/CRS, Policies, "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis (SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe," updated November 2012, (PPI TR–3/2012), IBR approved for § 192.121.

(2) PPI TR–4, HDB/HDS/SDB/MRS, Listed Materials, "PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Rating For Thermoplastic Piping Materials or Pipe," updated March, 2011, (PPI TR–4/2012), IBR approved for § 192.121.

■ 4. In § 192.9 revise paragraph (d) to read as follows:

§ 192.9 What requirements apply to gathering lines?

* * * * *

(d) *Type B lines.* An operator of a Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines;

(3) If the pipeline contains plastic pipe or components, the operator must comply with all applicable requirements of this part for plastic pipe components;

(4) Carry out a damage prevention program under § 192.614;

(5) Establish a public education program under § 192.616;

(6) Establish the MAOP of the line under § 192.619;

(7) Install and maintain line markers according to the requirements for transmission lines in § 192.707; and

(8) Conduct leakage surveys in accordance with the requirements for transmission lines in § 192.706, using leak-detection equipment, and promptly repair hazardous leaks in accordance with § 192.703(c).

* * * * *

■ 5. Amend § 192.59 as follows:

■ a. Revise paragraphs (a)(1) and (a)(2);

■ b. Add paragraph (a)(3): and

■ c. Revise paragraph (b)(3).

The revisions and addition read as follows:

§ 192.59 Plastic pipe.

(a) * * *

(1) It is manufactured in accordance with a listed specification;

(2) It is resistant to chemicals with which contact may be anticipated; and

(3) It is free of visible defects.

(b) * * *

(3) It has been used only in gas service;

* * * * *

■ 6. Amend § 192.63 by revising paragraph (a) and adding paragraph (e) to read as follows:

§ 192.63 Marking of materials.

(a) Except as provided in paragraph (d) and (e) of this section, each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured.

* * * * *

(e) All plastic pipe and components must also meet the following requirements:

(1) All markings on plastic pipe prescribed in the listed specification and the requirements of paragraph (e)(2) of this section must be repeated at intervals not exceeding two feet.

(2) Plastic pipe and components manufactured after December 31, 2019 must be marked in accordance with the listed specification.

(3) All physical markings on plastic pipelines prescribed in the listed specification and paragraph (e)(2) of this section must be legible until the time of installation.

■ 7. Add § 192.67 to subpart B to read as follows:

§ 192.67 Storage and handling of plastic pipe and associated components.

Each operator must have and follow written procedures for the storage and handling of plastic pipe and associated components that meet the applicable listed specifications.

■ 8. Revise § 192.121 to read as follows:

§ 192.121 Design of plastic pipe.

(a) *Design formula.* Design formulas for plastic pipe are determined in accordance with either of the following formulas:

$$P = 2S\frac{t}{(D-t)}(DF)$$

$$P = \frac{2S}{(SDR-1)}(DF)$$

P = Design pressure, gage, psi (kPa).

S = For thermoplastic pipe, the hydrostatic design basis (HDB) is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR–3/2012, (incorporated by reference, *see* § 192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa).

t = Specified wall thickness, inches (mm).

D = Specified outside diameter, inches (mm).

SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute (ANSI) preferred number series 10.

DF = Design Factor, a maximum of 0.32 unless otherwise specified for a particular material in this section

(b) *General requirements for plastic pipe and components.* (1) Except as provided in paragraphs (c) through (f) of this section, the design pressure for plastic pipe may not exceed a gauge pressure of 100 psig (689 kPa) for pipe used in:

(i) Distribution systems; or

(ii) Transmission lines in Class 3 and 4 locations.

(2) Plastic pipe may not be used where operating temperatures of the pipe will be:

(i) Below −20 °F (−29 °C), or below −40 °F (−40 °C) if all pipe and pipeline components whose operating temperature will be below −20 °F (−29 °C) have a temperature rating by the manufacturer consistent with that operating temperature; or

(ii) Above the temperature at which the HDB used in the design formula under this section is determined.

(3) Unless specified for a particular material in this section, the wall thickness of plastic pipe may not be less than 0.062 inches (1.57 millimeters).

(4) All plastic pipe must have a listed HDB in accordance with PPI TR–4/2012 (incorporated by reference, *see* § 192.7).

(c) *Polyethylene (PE) pipe requirements.* (1) For PE pipe produced after July 14, 2004, but before January 22, 2019, a design pressure of up to 125 psig may be used, provided:

(i) The material designation code is PE2406 or PE3408.

(ii) The pipe has a nominal size (Iron Pipe Size (IPS) or Copper Tubing Size (CTS)) of 12 inches or less (above nominal pipe size of 12 inches, the design pressure is limited to 100 psig); and

(iii) The wall thickness is not less than 0.062 inches (1.57 millimeters).

(2) For PE pipe produced after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

(i) The design pressure does not exceed 125 psig;

(ii) The material designation code is PE2708 or PE4710;

(iii) The pipe has a nominal size (IPS or CTS) of 12 inches or less; and

(iv) The wall thickness for a given outside diameter is not less than that listed in the following table:

PE PIPE—MINIMUM WALL THICKNESS AND SDR VALUES

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
½″ CTS	0.090	7
¾″ CTS	0.090	9.7
½″ IPS	0.090	9.3
¾″ IPS	0.095	11
1″ CTS	0.119	11
1″ IPS	0.119	11
1¼″ IPS	0.151	11
1½″ IPS	0.173	11
2″	0.216	11
3″	0.259	13.5
4″	0.265	17
6″	0.315	21
8″	0.411	21
10″	0.512	21
12″	0.607	21

(d) *Polyamide (PA–11) pipe requirements.* (1) For PA–11 pipe produced after January 23, 2009, but before January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

(i) The design pressure does not exceed 200 psig;

(ii) The material designation code is PA32312 or PA32316;

(iii) The pipe has a nominal size (IPS or CTS) of 4 inches or less; and

(iv) The pipe has a standard dimension ratio of SDR–11 or less (*i.e.*, thicker wall pipe).

(2) For PA–11 pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

(i) The design pressure does not exceed 250 psig;

(ii) The material designation code is PA32316;

(iii) The pipe has a nominal size (IPS or CTS) of 6 inches or less; and

(iv) The minimum wall thickness for a given outside diameter is not less than that listed in the following table:

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
¾″ CTS	0.090	9.7
½″ IPS	0.090	9.3
¾″ IPS	0.095	11
1″ CTS	0.119	11
1″ IPS	0.119	11
1¼ IPS	0.151	11
1½″ IPS	0.173	11
2″ IPS	0.216	11
3″ IPS	0.259	13.5
4″ IPS	0.333	13.5
6″ IPS	0.491	13.5

(e) *Polyamide (PA–12) pipe requirements.* For PA–12 pipe produced after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

(1) The design pressure does not exceed 250 psig;

(2) The material designation code is PA42316;

(3) The pipe has a nominal size (IPS or CTS) of 6 inches or less; and

(4) The minimum wall thickness for a given outside diameter is not less than that listed in the following table.

PA–12 PIPE—MINIMUM WALL THICKNESS AND SDR VALUES

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

(f) *Reinforced thermosetting plastic pipe requirements.* (1) Reinforced thermosetting plastic pipe may not be used at operating temperatures above 150 °F (66 °C).

(2) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches (millimeters)	Minimum wall thickness in inches (millimeters)
2 (51)	0.060 (1.52)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

§ 192.123 [Removed and Reserved]

■ 9. Remove and reserve § 192.123

■ 10. In § 192.143, add paragraph (c) to read as follows:

§ 192.143 General requirements.

* * * * *

(c) Except for excess flow valves, each plastic pipeline component installed after January 22, 2019 must be able to withstand operating pressures and other anticipated loads in accordance with a listed specification.

■ 11. In § 192.145, add paragraph (f) to read as follows:

§ 192.145 Valves.

* * * * *

(f) Except for excess flow valves, plastic valves installed after January 22, 2019, must meet the minimum requirements of a listed specification. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in the listed specification.

■ 12. In § 192.149, add paragraph (c) to read as follows:

§ 192.149 Standard fittings.

* * * * *

(c) Plastic fittings installed after January 22, 2019, must meet a listed specification.

§ 192.191 [Removed and Reserved]

■ 13. Remove and reserve § 192.191.

■ 14. Add § 192.204 to subpart D to read as follows:

§ 192.204 Risers installed after January 22, 2019.

(a) Riser designs must be tested to ensure safe performance under anticipated external and internal loads acting on the assembly.

(b) Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973–13 (incorporated by reference, *see* § 192.7).

(c) All risers used to connect regulator stations to plastic mains must be rigid and designed to provide adequate support and resist lateral movement. Anodeless risers used in accordance with this paragraph must have a rigid riser casing.

■ 15. Amend § 192.281 by revising paragraphs (b)(2), (b)(3), and (c) and adding paragraphs (e)(3) and (e)(4) to read as follows:

§ 192.281 Plastic pipe.

* * * * *

(b) * * *

(2) The solvent cement must conform to ASTM D2564–12 for PVC (incorporated by reference, *see* § 192.7).

(3) The joint may not be heated or cooled to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620–12 (incorporated by reference in § 192.7) and the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the pipe or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under § 192.283.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the pipe or component, uniformly and simultaneously, to establish the same temperature. The device used must be the same device specified in the operator's joining procedure for socket fusion.

(3) An electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer, or using equipment and techniques shown, by testing joints to the requirements of § 192.283(a)(1)(iii), to be equivalent to or better than the requirements of the fitting manufacturer.

(4) Heat may not be applied with a torch or other open flame.

* * * * *

(e) * * *

(3) All mechanical fittings must meet a listed specification based upon the applicable material.

(4) All mechanical joints or fittings installed after January 22, 2019, must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

■ 16. Revise § 192.283 to read as follows:

§ 192.283 Plastic pipe: Qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under § 192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints that are made according to the procedure to the following tests, as applicable:

(1) The test requirements of—

(i) In the case of thermoplastic pipe, based on the pipe material, the Sustained Pressure Test or the Minimum Hydrostatic Burst Test per the listed specification requirements. Additionally, for electrofusion joints, based on the pipe material, the Tensile Strength Test or the Joint Integrity Test per the listed specification.

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517- 00 (incorporated by reference, *see* § 192.7).

(iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055–98(2006) (incorporated by reference, *see* § 192.7).

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use.

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

(b) *Mechanical joints.* Before any written procedure established under § 192.273(b) is used for making mechanical plastic pipe joints, the procedure must be qualified in accordance with a listed specification based upon the pipe material.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

■ 17. 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), or for PE heat fusion joints (except for electrofusion joints) visually inspected and tested in accordance with ASTM F2620–12 (incorporated by reference, *see* § 192.7) applicable to the type of joint and material being tested;

* * * * *

■ 18. In § 192.313, add paragraph (d) to read as follows:

§ 192.313 Bends and elbows.

* * * * *

(d) An operator may not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.

■ 19. Amend § 192.321 by revising paragraphs (a), (d), (f), and (h)(3) and adding paragraph (i) to read as follows:

§ 192.321 Installation of plastic pipelines.

(a) Plastic pipe must be installed below ground level except as provided in paragraphs (g), (h), and (i) of this section.

* * * * *

(d) Plastic pipe must have a minimum wall thickness in accordance with § 192.121.

* * * * *

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. Plastic pipe that is being encased must be protected from damage at all entrance and all exit points of the casing. The leading end of the plastic must be closed before insertion.

* * * * *

(h) * * *

(3) Not allowed to exceed the pipe temperature limits specified in § 192.121.

(i) Plastic mains may terminate above ground level provided they comply with the following:

(1) The above-ground level part of the plastic main is protected against deterioration and external damage.

(2) The plastic main is not used to support external loads.

(3) Installations of risers at regulator stations must meet the design requirements of § 192.204.

■ 20. Add § 192.329 to subpart G to read as follows:

§ 192.329 Installation of plastic pipelines by trenchless excavation.

Plastic pipelines installed by trenchless excavation must comply with the following:

(a) Each operator must take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and/or structures at the time of installation.

(b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by § 192.3, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

■ 21. Amend § 192.367 by revising paragraphs (b)(1) and (b)(2) and adding paragraph (b)(3) to read as follows:

§ 192.367 Service lines: General requirements for connections to main piping.

* * * * *

(b) * * *

(1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading;

(2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system; and

(3) If used on pipelines comprised of plastic, be a Category 1 connection as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

■ 22. In § 192.375, revise paragraph (a)(2) to read as follows:

§ 192.375 Service lines: Plastic.

(a) * * *

(2) It may terminate above ground level and outside the building, if—

(i) The above ground level part of the plastic service line is protected against deterioration and external damage;

(ii) The plastic service line is not used to support external loads; and

(iii) The riser portion of the service line meets the design requirements of § 192.204.

* * * * *

■ 23. Add § 192.376 to read as follows:

§ 192.376 Installation of plastic service lines by trenchless excavation.

Plastic service lines installed by trenchless excavation must comply with the following:

(a) Each operator shall take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and structures at the time of installation.

(b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by § 192.3, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

■ 24. Amend § 192.455 by revising paragraph (a) introductory text and adding paragraph (g) to read as follows:

§ 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), (f), and (g) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

* * * * *

(g) Electrically isolated metal alloy fittings installed after January 22, 2019, that do not meet the requirements of paragraph (f) must be cathodically protected, and must be maintained in accordance with the operator's integrity management plan.

■ 25. In § 192.513, revise paragraph (c) to read as follows:

§ 192.513 Test requirements for plastic pipelines.

* * * * *

(c) The test pressure must be at least 150% of the maximum operating pressure or 50 psi (345 kPa) gauge, whichever is greater. However, the maximum test pressure may not be more than 2.5 times the pressure determined under § 192.121 at a temperature not less than the pipe temperature during the test.

* * * * *

■ 26. Add § 192.720 to read as follows:

§ 192.720 Distribution systems: Leak repair.

Mechanical leak repair clamps installed after January 22, 2019 may not be used as a permanent repair method for plastic pipe.

■ 27. Add § 192.756 to subpart M to read as follows:

§ 192.756 Joining plastic pipe by heat fusion; equipment maintenance and calibration.

Each operator must maintain equipment used in joining plastic pipe in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.

■ 28. In Appendix B to Part 192, revise the appendix heading and the list under "I." to read as follows:

Appendix B to Part 192—Qualification of Pipe and Components

I. List of Specifications

A. Listed Pipe Specifications

API Spec 5L—Steel pipe, "API Specification for Line Pipe" (incorporated by reference, *see* § 192.7).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference, *see* § 192.7).

ASTM A106/A–106M—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference, *see* § 192.7).

ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference, *see* § 192.7).

ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference, *see* § 192.7).

ASTM A671/A671M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference, *see* § 192.7).

ASTM A672/A672M–09—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference, *see* § 192.7).

ASTM A691/A691M–09—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures" (incorporated by reference, *see* § 192.7).

ASTM D2513–12ae1"Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, see § 192.7).

ASTM D 2517–00—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, *see* § 192.7).

ASTM F2785–12 "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings" (PA–12) (incorporated by reference, *see* § 192.7).

ASTM F2817–10 "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference, *see* § 192.7).

ASTM F2945–12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings" (PA–11) (incorporated by reference, *see* § 192.7).

B. Other Listed Specifications for Components

ASME B16.40–2008 "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems" (incorporated by reference, *see* § 192.7).

ASTM D2513–12ae1"Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, see § 192.7).

ASTM D 2517–00—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, *see* § 192.7).

ASTM F2785–12 "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings" (PA–12) (incorporated by reference, *see* § 192.7).

ASTM F2945–12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings" (PA–11) (incorporated by reference, *see* § 192.7).

ASTM F1055–98 (2006) "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (incorporated by reference, *see* § 192.7).

ASTM F1924–12 "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing" (incorporated by reference, *see* § 192.7).

ASTM F1948–12 "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing" (incorporated by reference, *see* § 192.7).

ASTM F1973–13 "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA 11) and Polyamide 12 (PA 12) Fuel Gas Distribution Systems" (incorporated by reference, *see* § 192.7).

ASTM F 2600–09 "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing" (incorporated by reference, *see* § 192.7).

ASTM F2145–13 "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing" (incorporated by reference, *see* § 192.7).

ASTM F2767–12 "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution" (incorporated by reference, *see* § 192.7).

ASTM F2817–10 "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference, *see* § 192.7).

* * * * *

Issued in Washington, DC, on November 9, 2018, under authority delegated in 49 CFR 1.97.

Howard R. Elliott,

Administrator.

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(5) Date condition was discovered and date condition was first determined to exist.

(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.

(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.

(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

[Amdt. 191-6, 53 FR 24949, July 1, 1988; 53 FR 29800, Aug. 8, 1988, as amended by Amdt. 191-7, 54 FR 32344, Aug. 7, 1989; Amdt. 191-8, 54 FR 40878, Oct. 4, 1989; Amdt. 191-10, 61 FR 18516, Apr. 26, 1996; Amdt. 191-23, 80 FR 12777, Mar. 11, 2015]

§ 191.29 National Pipeline Mapping System.

(a) Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:

(1) Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at *www.npms.phmsa.dot.gov* or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

(2) The name of and address for the operator.

(3) The name and contact information of a pipeline company employee, to be displayed on a public Web site, who will serve as a contact for questions from the general public about the operator's NPMS data.

(b) The information required in paragraph (a) of this section must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available at *www.npms.phmsa.dot.gov* or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595.

[Amdt. 191-23, 80 FR 12777, Mar. 11, 2015]

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

Subpart A—General

Subpart B—Materials

Subpart C—Pipe Design

Subpart D—Design of Pipeline Components

Subpart E—Welding of Steel in Pipelines

Subpart F—Joining of Materials Other Than by Welding

Subpart G—General Construction Requirements for Transmission Lines and Mains

Subpart H—Customer Meters, Service Regulators, and Service Lines

Subpart I—Requirements for Corrosion Control

Subpart J—Test Requirements

Subpart K—Uprating

Subpart L—Operations

Subpart M—Maintenance

Subpart N—Qualification of Pipeline Personnel

Subpart O—Gas Transmission Pipeline Integrity Management

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

AUTHORITY: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, 60137, 60141; and 49 CFR 1.97.

SOURCE: 35 FR 13257, Aug. 19, 1970, unless otherwise noted.

EDITORIAL NOTE: Nomenclature changes to part 192 appear at 71 FR 33406, June 9, 2006.

Subpart A—General

§ 192.1 What is the scope of this part?

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to—

(1) Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9;

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator;

(4) Onshore gathering of gas—

(i) Through a pipeline that operates at less than 0 psig (0 kPa);

(ii) Through a pipeline that is not a regulated onshore gathering line (as determined in § 192.8); and

(iii) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612; or

(5) Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—

(i) Fewer than 10 customers, if no portion of the system is located in a public place; or

(ii) A single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–27, 41 FR 34605, Aug. 16, 1976; Amdt. 192–67, 56 FR 63771, Dec. 5, 1991; Amdt. 192–78, 61 FR 28782, June 6, 1996; Amdt. 192–81, 62 FR 61695, Nov. 19, 1997; Amdt. 192–92, 68 FR 46112, Aug. 5, 2003; 70 FR 11139, Mar. 8, 2005; Amdt. 192–102, 71 FR 13301, Mar. 15, 2006; Amdt. 192–103, 72 FR 4656, Feb. 1, 2007]

§ 192.3 Definitions.

As used in this part:

Abandoned means permanently removed from service.

Active corrosion means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.

Administrator means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

Controller means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.

Customer meter means the meter that measures the transfer of gas from an operator to a consumer.

Distribution line means a pipeline other than a gathering or transmission line.

Electrical survey means a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

Exposed underwater pipeline means an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.

Gas means natural gas, flammable gas, or gas which is toxic or corrosive.

Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main.

Gulf of Mexico and its inlets means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

Hazard to navigation means, for the purposes of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from the mean low water.

High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Line section means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

Listed specification means a specification listed in section I of appendix B of this part.

Low-pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

Main means a distribution line that serves as a common source of supply for more than one service line.

Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Municipality means a city, county, or any other political subdivision of a State.

Offshore means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator means a person who engages in the transportation of gas.

Outer Continental Shelf means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

Petroleum gas means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 °F (38 °C).

Pipe means any pipe or tubing used in the transportation of gas, including pipe-type holders.

Pipeline means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

Pipeline environment includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

Pipeline facility means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

Service line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

Service regulator means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

SMYS means specified minimum yield strength is:

(1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with § 192.107(b).

State means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

Supervisory Control and Data Acquisition (SCADA) system means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

NOTE: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

Underground natural gas storage facility means a facility that stores natural gas in an underground facility incident to natural gas transportation, including—

(1) A depleted hydrocarbon reservoir;

(2) An aquifer reservoir; or

(3) A solution-mined salt cavern reservoir, including associated material and equipment used for injection, withdrawal, monitoring, or observation wells, and wellhead equipment, piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment.

Welder means a person who performs manual or semi-automatic welding.

Welding operator means a person who operates machine or automatic welding equipment.

[Amdt. 192–13, 38 FR 9084, Apr. 10, 1973]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.3, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.fdsys.gov*.

§ 192.5 Class locations.

(a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.

(1) A "class location unit" is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1- mile (1.6 kilometers) length of pipeline.

(2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

(1) A Class 1 location is:

(i) An offshore area; or

(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

(2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

(3) A Class 3 location is:

(i) Any class location unit that has 46 or more buildings intended for human occupancy; or

(ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:

(1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

[Amdt. 192–78, 61 FR 28783, June 6, 1996; 61 FR 35139, July 5, 1996, as amended by Amdt. 192–85, 63 FR 37502, July 13, 1998]

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

(a) This part prescribes standards, or portions thereof, incorporated by reference into this part with the approval of the Director of the Federal Register in 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. To enforce any edition other than that specified in this section, PHMSA must publish a notice of change in the FEDERAL REGISTER.

(1) *Availability of standards incorporated by reference.* All of the materials incorporated by reference are available for inspection from several sources, including the following:

(i) The Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. For more information contact 202–366–4046 or go to the PHMSA Web site at: *http://www.phmsa.dot.gov/pipeline/regs.*

(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030 or go to the NARA Web site at: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(iii) Copies of standards incorporated by reference in this part can also be purchased or are otherwise made available from the respective standards-developing organization at the addresses provided in the centralized IBR section below.

(2) [Reserved]

(b) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, phone: 202–682–8000, *http://api.org/.*

(1) API Recommended Practice 5L1, "Recommended Practice for Railroad Transportation of Line Pipe," 7th edition, September 2009, (API RP 5L1), IBR approved for § 192.65(a).

(2) API Recommended Practice 5LT, "Recommended Practice for Truck Transportation of Line Pipe," First edition, March 2012, (API RP 5LT), IBR approved for § 192.65(c).

(3) API Recommended Practice 5LW, "Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels," 3rd edition, September 2009, (API RP 5LW), IBR approved for § 192.65(b).

(4) API Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines," 1st edition, April 2000, (API RP 80), IBR approved for § 192.8(a).

(5) API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," 1st edition, December 2003, (API RP 1162), IBR approved for § 192.616(a), (b), and (c).

(6) API Recommended Practice 1165, "Recommended Practice for Pipeline SCADA Displays," First edition, January 2007, (API RP 1165), IBR approved for § 192.631(c).

(7) API Specification 5L, "Specification for Line Pipe," 45th edition, effective July 1, 2013, (API Spec 5L), IBR approved for §§ 192.55(e); 192.112(a), (b), (d), (e); 192.113; and Item I, Appendix B to Part 192.

(8) ANSI/API Specification 6D, "Specification for Pipeline Valves,"23rd edition, effective October 1, 2008, including Errata 1 (June 2008), Errata2 (/November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011) Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012), (ANSI/API Spec 6D), IBR approved for § 192.145(a).

(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(c); 192.241(c); and Item II, Appendix B.

(10) API Recommended Practice 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," First edition, July 2015 (API RP 1170), IBR approved for § 192.12.

(11) API Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," First edition, September 2015, (API RP 1171), IBR approved for § 192.12.

(c) ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), *http://www.asme.org/*.

(1) ASME/ANSI B16.1-2005, "Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)," August 31, 2006, (ASME/ANSI B16.1), IBR approved for § 192.147(c).

(2) ASME/ANSI B16.5-2003, "Pipe Flanges and Flanged Fittings, "October 2004, (ASME/ANSI B16.5), IBR approved for §§ 192.147(a) and 192.279.

(3) ASME/ANSI B31G-1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ANSI B31G), IBR approved for §§ 192.485(c) and 192.933(a).

(4) ASME/ANSI B31.8-2007, "Gas Transmission and Distribution Piping Systems," November 30, 2007, (ASME/ ANSI B31.8), IBR approved for §§ 192.112(b) and 192.619(a).

(5) ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," 2004, (ASME/ ANSI B31.8S-2004), IBR approved for §§ 192.903 note to *Potential impact radius;* 192.907 introductory text, (b); 192.911 introductory text, (i), (k), (l), (m); 192.913(a), (b), (c); 192.917 (a), (b), (c), (d), (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b), (c); 192.929(b); 192.933(c), (d); 192.935 (a), (b); 192.937(c); 192.939(a); and 192.945(a).

(6) ASME Boiler & Pressure Vessel Code, Section I, "Rules for Construction of Power Boilers 2007," 2007 edition, July 1, 2007, (ASME BPVC, Section I), IBR approved for § 192.153(b).

(7) ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 "Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1), IBR approved for §§ 192.153(a), (b), (d); and 192.165(b).

(8) ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 "Alternate Rules, Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2), IBR approved for §§ 192.153(b), (d); and 192.165(b).

(9) ASME Boiler & Pressure Vessel Code, Section IX: "Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators," 2007 edition, July 1, 2007, ASME BPVC, Section IX, IBR approved for §§ 192.225(a); 192.227(a); and Item II, Appendix B to Part 192.

(d) American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, Web site: *http://www.astm.org/*.

(1) ASTM A53/A53M–10, "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless," approved October 1, 2010, (ASTM A53/A53M), IBR approved for § 192.113; and Item II, Appendix B to Part 192.

(2) ASTM A106/A106M–10, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service," approved October 1, 2010, (ASTM A106/A106M), IBR approved for § 192.113; and Item I, Appendix B to Part 192.

(3) ASTM A333/A333M–11, "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service," approved April 1, 2011, (ASTM A333/A333M), IBR approved for § 192.113; and Item I, Appendix B to Part 192.

(4) ASTM A372/A372M–10, "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels," approved October 1, 2010, (ASTM A372/A372M), IBR approved for § 192.177(b).

(5) ASTM A381–96 (reapproved 2005), "Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems," approved October 1, 2005, (ASTM A381), IBR approved for § 192.113; and Item I, Appendix B to Part 192.

(6) ASTM A578/A578M–96 (reapproved 2001), "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications," (ASTM A578/A578M), IBR approved for § 192.112(c).

(7) ASTM A671/A671M–10, "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures," approved April 1, 2010, (ASTM A671/A671M), IBR approved for § 192.113; and Item I, Appendix B to Part 192.

(8) ASTM A672/A672M–09, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures," approved October 1, 2009, (ASTM A672/672M), IBR approved for § 192.113 and Item I, Appendix B to Part 192.

(9) ASTM A691/A691M–09, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures," approved October 1, 2009, (ASTM A691/A691M), IBR approved for § 192.113 and Item I, Appendix B to Part 192.

(10) ASTM D638–03, "Standard Test Method for Tensile Properties of Plastics," 2003, (ASTM D638), IBR approved for § 192.283(a) and (b).

(11) ASTM D2513–87, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings," (ASTM D2513–87), IBR approved for § 192.63(a).

(12) ASTM D2513–99, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings," (ASTM D 2513–99), IBR approved for §§ 192.191(b); 192.281(b); 192.283(a) and Item 1, Appendix B to Part 192.

(13) ASTM D2513–09a, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings," approved December 1, 2009, (ASTM D2513–09a), IBR approved for §§ 192.123(e); 192.191(b); 192.283(a); and Item 1, Appendix B to Part 192.

(14) ASTM D2517–00, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings," (ASTM D 2517), IBR approved for §§ 192.191(a); 192.281(d); 192.283(a); and Item I, Appendix B to Part 192.

(15) ASTM F1055–1998, "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controller Polyethylene Pipe and Tubing," (ASTM F1055), IBR approved for § 192.283(a).

(e) Gas Technology Institute (GTI), formerly the Gas Research Institute (GRI)), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847–768–0500, Web site: *www.gastechnology.org*.

(1) GRI 02/0057 (2002) "Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology," (GRI 02/0057), IBR approved for § 192.927(c).

(2) [Reserved]

(f) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703–281–6613, Web site: *http://www.mss-hq.org/*.

(1) MSS SP–44–2010, Standard Practice, "Steel Pipeline Flanges," 2010 edition, (including Errata (May 20, 2011)), (MSS SP–44), IBR approved for § 192.147(a).

(2) [Reserved]

(g) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084:

phone: 281–228–6223 or 800–797–6223, Web site: *http://www.nace.org/Publications/.*

(1) ANSI/NACE SP0502–2010, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology," revised June 24, 2010, (NACE SP0502), IBR approved for §§ 192.923(b); 192.925(b); 192.931(d); 192.935(b) and 192.939(a).

(2) [Reserved]

(h) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984–7275, Web site: *http://www.nfpa.org/.*

(1) NFPA–30 (2012), "Flammable and Combustible Liquids Code," 2012 edition, June 20, 2011, including Errata 30–12–1 (September 27, 2011) and Errata 30–12–2 (November 14, 2011), (NFPA–30), IBR approved for § 192.735(b).

(2) NFPA–58 (2004), "Liquefied Petroleum Gas Code (LP-Gas Code)," (NFPA–58), IBR approved for § 192.11(a), (b), and (c).

(3) NFPA–59 (2004), "Utility LP-Gas Plant Code," (NFPA–59), IBR approved for § 192.11(a), (b); and (c).

(4) NFPA–70 (2011), "National Electrical Code," 2011 edition, issued August 5, 2010, (NFPA–70), IBR approved for §§ 192.163(e); and 192.189(c).

(i) Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713–630–0505, toll free: 866–866–6766, Web site: *http://www.ttoolboxes.com/*. (Contract number PR–3–805.)

(1) AGA, Pipeline Research Committee Project, PR–3–805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR–3–805 (R-STRENG)), IBR approved for §§ 192.485(c); 192.933(a) and (d).

(2) [Reserved]

(j) Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469–499–1044, *http://www.plasticpipe.org/.*

(1) PPI TR–3/2008 HDB/HDS/PDB/SDB/MRS Policies (2008), "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe," May 2008, IBR approved for § 192.121.

(2) [Reserved]

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.7, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.fdsys.gov.*

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

(a) An operator must use API RP 80 (incorporated by reference, see § 192.7), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under paragraph (b) of this section.

(1) The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not extend beyond the furthermost downstream point in a production operation as defined in section 2.3 of API RP 80. This furthermost downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of "production and preparation for transportation or delivery of hydrocarbon gas" within the meaning of "production operation."

(2) The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.

(3) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR § 190.9).

(4) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthermost

downstream compressor used to increase gathering line pressure for delivery to another pipeline.

(b) For purposes of § 192.9, "regulated onshore gathering line" means:

(1) Each onshore gathering line (or segment of onshore gathering line) with a feature described in the second column that lies in an area described in the third column; and

(2) As applicable, additional lengths of line described in the fourth column to provide a safety buffer:

Type	Feature	Area	Safety buffer
A	—Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is more than 125 psig (862 kPa).	Class 2, 3, or 4 location (*see* § 192.5)	None.
B	—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is 125 psig (862 kPa) or less.	*Area 1.* Class 3 or 4 location *Area 2.* An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location. (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings. (c) An area extending 150 feet (45.7 m) on each side of the canterline of any continous 1000 feet (305 m) of pipaline and including 5 or more dwellings.	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2 (b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.

[Amdt. 192–102, 71 FR 13302, Mar. 15, 2006]

§ 192.9 What requirements apply to gathering lines?

(a) *Requirements.* An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in § 192.150 and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in § 192.150 and in subpart O of this part. However, an operator of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) *Type B lines.* An operator of a Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines;

(3) Carry out a damage prevention program under § 192.614;

(4) Establish a public education program under § 192.616;

(5) Establish the MAOP of the line under § 192.619; and

(6) Install and maintain line markers according to the requirements for transmission lines in § 192.707.

(7) Conduct leakage surveys in accordance with § 192.706 using leak detection equipment and promptly repair

hazardous leaks that are discovered in accordance with § 192.703(c).

(e) *Compliance deadlines.* An operator of a regulated onshore gathering line must comply with the following deadlines, as applicable.

(1) An operator of a new, replaced, relocated, or otherwise changed line must be in compliance with the applicable requirements of this section by the date the line goes into service, unless an exception in § 192.13 applies.

(2) If a regulated onshore gathering line existing on April 14, 2006 was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the line listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

Requirement	Compliance deadline
Control corrosion according to Subpart I requirements for transmission lines.	April 15, 2009.
Carry out a damage prevention program under § 192.614.	October 15, 2007.
Establish MAOP under § 192.619.	October 15, 2007.
Install and maintain line markers under § 192.707.	April 15, 2008.
Establish a public education program under § 192.616.	April 15, 2006.
Other provisions of this part as required by paragraph (c) of this section for Type A lines.	April 15, 2009.

(3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section.

[Amdt. 192-102, 71 FR 13301, Mar. 15, 2006, as amended by Amdt. 192-120, 80 FR 12777, Mar. 11, 2015]

§ 192.10 Outer continental shelf pipelines.

Operators of transportation pipelines on the Outer Continental Shelf (as defined in the Outer Continental Shelf Lands Act; 43 U.S.C. 1331) must identify on all their respective pipelines the specific points at which operating responsibility transfers to a producing operator. For those instances in which the transfer points are not identifiable by a durable marking, each operator will have until September 15, 1998 to identify the transfer points. If it is not practicable to durably mark a transfer point and the transfer point is located above water, the operator must depict the transfer point on a schematic located near the transfer point. If a transfer point is located subsea, then the operator must identify the transfer point on a schematic which must be maintained at the nearest upstream facility and provided to PHMSA upon request. For those cases in which adjoining operators have not agreed on a transfer point by September 15, 1998 the Regional Director and the MMS Regional Supervisor will make a joint determination of the transfer point.

[Amdt. 192-81, 62 FR 61695, Nov. 19, 1997, as amended at 70 FR 11139, Mar. 8, 2005]

§ 192.11 Petroleum gas systems.

(a) Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and NFPA 58 and NFPA 59 (incorporated by reference, *see* § 192.7).

(b) Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and of ANSI/NFPA 58 and 59.

(c) In the event of a conflict between this part and NFPA 58 and NFPA 59 (incorporated by reference, *see* § 192.7), NFPA 58 and NFPA 59 prevail.

[Amdt. 192-78, 61 FR 28783, June 6, 1996, as amended by Amdt. 192-119, 80 FR 180, Jan. 5, 2015; 80 FR 46847, Aug. 6, 2015]

§ 192.12 Underground natural gas storage facilities.

Underground natural gas storage facilities must meet the following requirements:

(a) Each underground natural gas storage facility that uses a solution-mined salt cavern reservoir for gas storage constructed after July 18, 2017 must meet all requirements and recommendations of API RP 1170 (incorporated by reference, see § 192.7).

(b) Each underground natural gas storage facility that uses a solution-mined salt cavern reservoir for storage including those constructed not later than July 18, 2017 must meet the operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping requirements and recommendations of API RP 1170, sections 9, 10, and 11 (incorporated by reference, see § 192.7) by January 18, 2018.

(c) Each underground natural gas storage facility that uses a depleted hydrocarbon reservoir or an aquifer reservoir for storage constructed after July 18, 2017 must meet all requirements and recommendations of API RP 1171 (incorporated by reference, see § 192.7).

(d) Each underground natural gas storage facility that uses a depleted hydrocarbon reservoir or an aquifer reservoir for gas storage, including those constructed not later than July 18, 2017 must meet the operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping requirements and recommendations of API RP 1171, sections 8, 9, 10, and 11 (incorporated by reference, see § 192.7) by January 18, 2018.

(e) Operators of underground gas storage facilities must establish and follow written procedures for operations, maintenance, and emergencies implementing the requirements of API RP 1170 and API RP 1171, as required under this section, including the effective dates as applicable, and incorporate such procedures into their written procedures for operations, maintenance, and emergencies established pursuant to § 192.605.

(f) With respect to the incorporation by reference of API RP 1170 and API RP 1171 in this section, the non-mandatory provisions (*i.e.*, provisions containing the word "should" or other non-mandatory language) are adopted as mandatory provisions under the authority of the pipeline safety laws except when the operator includes or references written technical justifications in its program or procedural manual, described in paragraph (a)(5) of this section, as to why compliance with a provision of the recommended practice is not practicable and not necessary for safety with respect to specified underground storage facilities or equipment. The justifications for any deviation from any provision of API RP 1170 and API RP 1171 must be technically reviewed and documented by a subject matter expert to ensure there will be no adverse impact on design, construction, operations, maintenance, integrity, emergency preparedness and response, and overall safety and must be dated and approved by a senior executive officer, vice president, or higher office with responsibility of the underground natural gas storage facility. An operator must discontinue use of any variance where PHMSA determines and provides notice that the variance adversely impacts design, construction, operations, maintenance, integrity, emergency preparedness and response, or overall safety.

[Amdt. 192–122, 81 FR 91873, Dec. 19, 2016]

§ 192.13 What general requirements apply to pipelines regulated under this part?

(a) No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part according to the requirements in § 192.14.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15 2007.
All other pipelines	March 12, 1971.

(b) No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15, 2007.
All other pipelines	November 12, 1970.

(c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-30, 42 FR 60148, Nov. 25, 1977; Amdt. 192-102, 71 FR 13303, Mar. 15, 2006]

§ 192.14 Conversion to service subject to this part.

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.

(2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.

(3) All known unsafe defects and conditions must be corrected in accordance with this part.

(4) The pipeline must be tested in accordance with subpart J of this part to substantiate the maximum allowable operating pressure permitted by subpart L of this part.

(b) Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.

(c) An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by § 191.22 of this chapter.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977, as amended by Amdt. 192-123, 82 FR 7997, Jan. 23, 2017]

§ 192.15 Rules of regulatory construction.

(a) As used in this part:

Includes means including but not limited to.

May means "is permitted to" or "is authorized to".

May not means "is not permitted to" or "is not authorized to".

Shall is used in the mandatory and imperative sense.

(b) In this part:

(1) Words importing the singular include the plural;

(2) Words importing the plural include the singular; and

(3) Words importing the masculine gender include the feminine.

§ 192.16 Customer notification.

(a) This section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this section, "customer's buried piping" does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, "maintain" means monitor for corrosion according to § 192.465 if the customer's buried piping is metallic, survey for leaks according to § 192.723, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition.

(b) Each operator shall notify each customer once in writing of the following information:

(1) The operator does not maintain the customer's buried piping.

(2) If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.

(3) Buried gas piping should be—

(i) Periodically inspected for leaks;

(ii) Periodically inspected for corrosion if the piping is metallic; and

(iii) Repaired if any unsafe condition is discovered.

(4) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.

(5) The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

(c) Each operator shall notify each customer not later than August 14, 1996, or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators of master meter systems may continuously post a general notice in a prominent location frequented by customers.

(d) Each operator must make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:

(1) A copy of the notice currently in use; and

(2) Evidence that notices have been sent to customers within the previous 3 years.

[Amdt. 192–74, 60 FR 41828, Aug. 14, 1995, as amended by Amdt. 192–74A, 60 FR 63451, Dec. 11, 1995; Amdt. 192–83, 63 FR 7723, Feb. 17, 1998]

Subpart B—Materials

§ 192.51 Scope.

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

§ 192.53 General.

Materials for pipe and components must be:

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this subpart.

§ 192.55 Steel pipe.

(a) New steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of—

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part; or

(3) It is used in accordance with paragraph (c) or (d) of this section.

(b) Used steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of appendix B to this part;

(2) It meets the requirements of:

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part;

(3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of appendix B to this part; or

(4) It is used in accordance with paragraph (c) of this section.

(c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of appendix B to this part.

(d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

(e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Spec 5L (incorporated by reference, *see* § 192.7).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 191-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-12, 38 FR 4761, Feb. 22, 1973; Amdt. 192-51, 51 FR 15335, Apr. 23, 1986; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-119, 80 FR 180, Jan. 5, 2015; 80 FR 46847, Aug. 6, 2015]

§ 192.57 [Reserved]

§ 192.59 Plastic pipe.

(a) New plastic pipe is qualified for use under this part if:

(1) It is manufactured in accordance with a listed specification; and

(2) It is resistant to chemicals with which contact may be anticipated.

(b) Used plastic pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It is resistant to chemicals with which contact may be anticipated;

(3) It has been used only in natural gas service;

(4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and

(5) It is free of visible defects.

(c) For the purpose of paragraphs (a)(1) and (b)(1) of this section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it:

(1) Meets the strength and design criteria required of pipe included in that listed specification; and

(2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

(d) Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015 used under this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-19, 40 FR 10472, Mar. 6, 1975; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§ 192.61 [Reserved]

§ 192.63 Marking of materials.

(a) Except as provided in paragraph (d) of this section, each valve, fitting, length of pipe, and other component must be marked—

(1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic pipe and fittings made of plastic materials other than polyethylene must be marked in accordance with ASTM D2513-87 (incorporated by reference, *see* § 192.7);

(2) To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192-31, 43 FR 883, Apr. 3, 1978; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; Amdt. 192-62, 54 FR 5627, Feb. 6, 1989; Amdt. 192-61A, 54 FR 32642, Aug. 9, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-76, 61 FR 26122, May 24, 1996; 61 FR 36826, July 15, 1996; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§ 192.65 Transportation of pipe.

(a) *Railroad*. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not install pipe having an outer diameter to wall thickness of 70 to 1, or more, that is transported by railroad unless the transportation is performed by API RP 5L1 (incorporated by reference, *see* § 192.7).

(b) *Ship or barge*. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference, *see* § 192.7).

(c) *Truck.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, *see* § 192.7).

[Amdt. 192–114, 75 FR 48603, Aug. 11, 2010, as amended by Amdt. 192–119, 80 FR 180, Jan. 5, 2015; Amdt. 192–120, 80 FR 12777, Mar. 11, 2015]

Subpart C—Pipe Design

§ 192.101 Scope.

This subpart prescribes the minimum requirements for the design of pipe.

§ 192.103 General.

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

§ 192.105 Design formula for steel pipe.

(a) The design pressure for steel pipe is determined in accordance with the following formula:

$$P = (2\ St/D) \times F \times E \times T$$

P = Design pressure in pounds per square inch (kPa) gauge.

S = Yield strength in pounds per square inch (kPa) determined in accordance with § 192.107.

D = Nominal outside diameter of the pipe in inches (millimeters).

t = Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with § 192.109. Additional wall thickness required for concurrent external loads in accordance with § 192.103 may not be included in computing design pressure.

F = Design factor determined in accordance with § 192.111.

E = Longitudinal joint factor determined in accordance with § 192.113.

T = Temperature derating factor determined in accordance with § 192.115.

(b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900 °F (482 °C) at any time or is held above 600 °F (316 °C) for more than 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–47, 49 FR 7569, Mar. 1, 1984; Amdt. 192–85, 63 FR 37502, July 13, 1998]

§ 192.107 Yield strength (*S*) for steel pipe.

(a) For pipe that is manufactured in accordance with a specification listed in section I of appendix B of this part, the yield strength to be used in the design formula in § 192.105 is the SMYS stated in the listed specification, if that value is known.

(b) For pipe that is manufactured in accordance with a specification not listed in section I of appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in § 192.105 is one of the following:

(1) If the pipe is tensile tested in accordance with section II-D of appendix B to this part, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests.

(2) If the pipe is not tensile tested as provided in paragraph (b)(1) of this section, 24,000 p.s.i. (165 MPa).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–78, 61 FR 28783, June 6, 1996; Amdt. 192–83, 63 FR 7723, Feb. 17, 1998; Amdt. 192–85, 63 FR 37502, July 13, 1998]

§ 192.109 Nominal wall thickness (*t*) for steel pipe.

(a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

(b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in § 192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37502, July 13, 1998]

§ 192.111 Design factor (*F*) for steel pipe.

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

Class location	Design factor (*F*)
1	0.72
2	0.60
3	0.50
4	0.40

(b) A design factor of 0.60 or less must be used in the design formula in § 192.105 for steel pipe in Class 1 locations that:

(1) Crosses the right-of-way of an unimproved public road, without a casing;

(2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;

(3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

(4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for—

(1) Steel pipe in a compressor station, regulating station, or measuring station; and

(2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–27, 41 FR 34605, Aug. 16, 1976]

§ 192.112 Additional design requirements for steel pipe using alternative maximum allowable operating pressure.

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure (MAOP) calculated under § 192.620, a segment must meet the following additional design requirements. Records for alternative MAOP must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this design issue:	The pipeline segment must meet these additional requirements:
(a) General standards for the steel pipe.	(1) The plate, skelp, or coil used for the pipe must be micro-alloyed, fine grain, fully killed, continuously cast steel with calcium treatment. (2) The carbon equivalents of the steel used for pipe must not exceed 0.25 percent by weight, as calculated by the Ito-Bessyo formula (Pcm formula) or 0.43 percent by weight, as calculated by the International Institute of Welding (IIW) formula. (3) The ratio of the specified outside diameter of the pipe to the specified wall thickness must be less than 100. The wall thickness or other mitigative measures must prevent denting and ovality anomalies during construction, strength testing and anticipated operational stresses. (4) The pipe must be manufactured using API Spec 5L, product specification level 2 (incorporated by reference, see § 192.7) for maximum operating pressures and minimum and maximum operating temperatures and other requirements under this section.

To address this design issue:	The pipeline segment must meet these additional requirements:
(b) Fracture control	(1) The toughness properties for pipe must address the potential for initiation, propegation and arrest of fractures in accordance with: (i) API Spec 5L (incorporated by reference, see § 192.7); or (ii) American Society of Mechanical Engineers (ASME) B31.8 (incorporated by reference, see § 192.7); and (iii) Any correction factors needed to address pipe grades, pressures, temperatures, or gas compositions not expressly addressed in API Spec 5L , product specification level 2 or ASME B31.8 (incorporated by reference, see § 192.7). (2) Fracture control must: (i) Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures, gas compositions, pipe grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions, that the pipeline is expected to experience. If these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline; (ii) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters; (iii) Ensure at least 99 percent probability of fracture arrest within eight pipe lengths with a probability of not less than 90 percent within five pipe lengths; and (iv) Include fracture toughness testing that is equivalent to that described in supplementary requirements SR5A, SR5B, and SR6 of API Specification 5L (incorporated by reference, see § 192.7) and ensures ductile fracture and arrest with the following exceptions: (A) The results of the Charpy impact test prescribed in SR5A must indicate at least 80 percent minimum shear area for any single test on each heat of steel; and (B) The results of the drop weight test prescribed in SR6 must indicate 80 percent average shear area with a minimum single test result of 60 percent shear area for any steel test samples. The test results must ensure a ductile fracture and arrest. (3) If it is not physically possible to achieve the pipeline toughness properties of paragraphs (b)(1) and (2) of this section, additional design features, such as mechanical or composite crack arrestors and/or heavier walled pipe of proper design and spacing, must be used to ensure fracture arrest as described in paragraph (b)(2)(iii) of this section.
(c) Plate/coil quality control	(1) There must be an internal quality management program at all mills involved in producing steel, plate, coil, skelp, and/or rolling pipe to be operated at alternative MAOP. These programs must be structured to eliminate or detect defects and inclusions affecting pipe quality. (2) A mill inspection program or internal quality management program must include (i) and either (ii) or (iii): (i) An ultrasonic test of the ends and at least 35 percent of the surface of the plate/coil or pipe to identify imperfections that impair serviceability such as laminations, cracks, and inclusions. At least 95 percent of the lengths of pipe manufactured must be tested. For all pipelines designed after December 22, 2008, the test must be done in accordance with ASTM A578/A578M Level B, or API Spec 5L Paragraph 7.8.10 (incorporated by reference, see § 192.7) or equivalent method, and either (ii) A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process. Use of sulfur prints is not an equivalent method. The test must be carried out on the first or second slab of each sequence graded with an acceptance criteria of one or two on the Mannesmann scale or equivalent; or (iii) A quality assurance monitoring program implemented by the operator that includes audits of: (a) all steelmaking and casting facilities, (b) quality control plans and manufacturing procedure specifications, (c) equipment maintenance and records of conformance, (d) applicable casting superheat and speeds, and (e) centerline segregation monitoring records to ensure mitigation of centerline segregation during the continuous casting process.
(d) Seam quality control	(1) There must be a quality assurance program for pipe seam welds to assure tensile strength provided in API Spec 5L (incorporated by reference, see § 192.7) for appropriate grades. (2) There must be a hardness test, using Vickers (Hv10) hardness test method or equivalent test method, to assure a maximum hardness of 280 Vickers of the following: (i) A cross section of the weld seam of one pipe from each heat plus one pipe from each welding line per day; and (ii) For each sample cross section, a minimum of 13 readings (three for each heat affected zone, three in the weld metal, and two in each section of pipe base metal). (3) All of the seams must be ultrasonically tested after cold expansion and mill hydrostatic testing.
(e) Mill hydrostatic test	(1) All pipe to be used in a new pipeline segment installed after October 1, 2015, must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds. (2) Pipe in operation prior to December 22, 2008, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 90 percent SMYS for 10 seconds. (3) Pipe in operation on or after December 22, 2008, but before October 1, 2015, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds. The test pressure may include a combination of internal test pressure and the allowance for end loading stresses imposed by the pipe mill hydrostatic testing equipment as allowed by "ANSI/API Spec 5L" (incorporated by reference, *see* § 192.7).
(f) Coating	(1) The pipe must be protected against external corrosion by a non-shielding coating.

To address this design issue:	The pipeline segment must meet these additional requirements:
	(2) Coating on pipe used for trenchless installation must be non-shielding and resist abrasions and other damage possible during installation. (3) A quality assurance inspection and testing program for the coating must cover the surface quality of the bare pipe, surface cleanliness and chlorides, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, coating thickness, holiday detection, and repair.
(g) Fittings and flanges	(1) There must be certification records of flanges, factory induction bends and factory weld ells. Certification must address material properties such as chemistry, minimum yield strength and minimum wall thickness to meet design conditions. (2) If the carbon equivalents of flanges, bends and ells are greater than 0.42 percent by weight, the qualified welding procedures must include a pre-heat procedure. (3) Valves, flanges and fittings must be rated based upon the required specification rating class for the alternative MAOP.
(h) Compressor stations	(1) A compressor station must be designed to limit the temperature of the nearest downstream segment operating at alternative MAOP to a maximum of 120 degrees Fahrenheit (49 degrees Celsius) or the higher temperature allowed in paragraph (h)(2) of this section unless a long-term coating integrity monitoring program is implemented in accordance with paragraph (h)(3) of this section. (2) If research, testing and field monitoring tests demonstrate that the coating type being used will withstand a higher temperature in long-term operations, the compressor station may be designed to limit downstream piping to that higher temperature. Test results and acceptance criteria addressing coating adhesion, cathodic disbondment, and coating condition must be provided to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operating above 120 degrees Fahrenheit (49 degrees Celsius). An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State. (3) Pipeline segments operating at alternative MAOP may operate at temperatures above 120 degrees Fahrenheit (49 degrees Celsius) if the operator implements a long-term coating integrity monitoring program. The monitoring program must include examinations using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or an equivalent method of monitoring coating integrity. An operator must specify the periodicity at which these examinations occur and criteria for repairing identified indications. An operator must submit its long-term coating integrity monitoring program to each PHMSA pipeline safety regional office in which the pipeline is located for review before the pipeline segments may be operated at temperatures in excess of 120 degrees Fahrenheit (49 degrees Celsius). An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

[73 FR 62175, Oct. 17, 2008, as amended by Amdt. 192–111, 74 FR 62505, Nov. 30, 2009; Amdt. 192–119, 80 FR 180, Jan. 5, 2015; Amdt. 192–120, 80 FR 12777, Mar. 11, 2015]

§ 192.113 Longitudinal joint factor (*E*) for steel pipe.

The longitudinal joint factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A 106	Seamless	1.00
ASTM A 333/A 333M	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric-fusion-welded	1.00
ASTM A 672	Electric-fusion-welded	1.00
ASTM A 691	Electric-fusion-welded	1.00
API Spec 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
Other	Pipe over 4 inches (102 millimeters)	.80
Other	Pipe 4 inches (102 millimeters) or less	.60

If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other."

[Amdt. 192–37, 46 FR 10159, Feb. 2, 1981, as amended by Amdt. 192–51, 51 FR 15335, Apr. 23, 1986; Amdt. 192–62, 54 FR 5627, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192–85, 63 FR 37502, July 13, 1998; Amdt. 192–94, 69 FR 32894, June 14, 2004; Amdt. 192–119, 80 FR 180, Jan. 5, 2015]

§ 192.115 Temperature derating factor (*T*) for steel pipe.

The temperature derating factor to be used in the design formula in § 192.105 is determined as follows:

Gas temperature in degrees Fahrenheit (Celsius)	Temperature derating factor (T)
250 °F (121 °C) or less	1.000
300 °F (149 °C)	0.967
350 °F (177 °C)	0.933
400 °F (204 °C)	0.900
450 °F (232 °C)	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37502, July 13, 1998]

§§ 192.117–192.119 [Reserved]

§ 192.121 Design of plastic pipe.

Subject to the limitations of § 192.123, the design pressure for plastic pipe is determined by either of the following formulas:

$$P = 2S\frac{t}{(D-t)}(DF)$$

$$P = \frac{2S}{(SDR-1)}(DF)$$

Where:

P = Design pressure, gauge, psig (kPa).

S = For thermoplastic pipe, the HDB is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR–3/2008, *HDB/PDB/SDB/MRS Policies* (incorporated by reference, *see* § 192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa). [Note: Arithmetic interpolation is not allowed for PA–11 pipe.]

t = Specified wall thickness, inches (mm).

D = Specified outside diameter, inches (mm).

SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.

D F = 0.32 or

= 0.40 for PA–11 pipe produced after January 23, 2009 with a nominal pipe size (IPS or CTS) 4-inch or less, and a SDR of 11 or greater (*i.e.*, thicker pipe wall).

[Amdt. 192–111, 74 FR 62505, Nov. 30, 2009, as amended by Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§ 192.123 Design limitations for plastic pipe.

(a) Except as provided in paragraph (e) and paragraph (f) of this section, the design pressure may not exceed a gauge pressure of 100 psig (689 kPa) for plastic pipe used in:

(1) Distribution systems; or

(2) Classes 3 and 4 locations.

(b) Plastic pipe may not be used where operating temperatures of the pipe will be:

(1) Below −20 °F (−20 °C), or −40 °F (−40 °C) if all pipe and pipeline components whose operating temperature will be below −29 °C (−20 °F) have a temperature rating by the manufacturer consistent with that operating temperature; or

(2) Above the following applicable temperatures:

(i) For thermoplastic pipe, the temperature at which the HDB used in the design formula under §192.121 is determined.

(ii) For reinforced thermosetting plastic pipe, 150 °F (66 °C).

(c) The wall thickness for thermoplastic pipe may not be less than 0.062 inches (1.57 millimeters).

(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches (millimeters).	Minimum wall thickness inches (millimeters).
2 (51)	0.060 (1.52)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

(e) The design pressure for thermoplastic pipe produced after July 14, 2004 may exceed a gauge pressure of 100 psig (689 kPa) provided that:

(1) The design pressure does not exceed 125 psig (862 kPa);

(2) The material is a polyethylene (PE) pipe with the designation code as specified within ASTM D2513–09a (incorporated by reference, *see* §192.7);

(3) The pipe size is nominal pipe size (IPS) 12 or less; and

(4) The design pressure is determined in accordance with the design equation defined in §192.121.

(f) The design pressure for polyamide-11 (PA–11) pipe produced after January 23, 2009 may exceed a gauge pressure of 100 psig (689 kPa) provided that:

(1) The design pressure does not exceed 200 psig (1379 kPa);

(2) The pipe size is nominal pipe size (IPS or CTS) 4-inch or less; and

(3) The pipe has a standard dimension ratio of SDR–11 or greater (*i.e.*, thicker pipe wall).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–31, 43 FR 13883, Apr. 3, 1978; Amdt. 192–78, 61 FR 28783, June 6, 1996; Amdt. 192–85, 63 FR 37502, July 13, 1998; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003; 69 FR 32894, June 14, 2004; Amdt. 192–94, 69 FR 54592, Sept. 9, 2004; Amdt. 192–103, 71 FR 33407, June 9, 2006; 73 FR 79005, Dec. 24, 2008; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010; Amdt. 192–119, 80 FR 181, Jan. 5, 2015]

§ 192.125 Design of copper pipe.

(a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.

(b) Copper pipe used in service lines must have wall thickness not less than that indicated in the following table:

Standard size inch (millimeter)	Nominal O.D. inch (millimeter)	Wall thickness inch (millimeter)	
		Nominal	Tolerance
½ (13)	.625 (16)	.040 (1.06)	.0035 (.0889)
⅝ (16)	.750 (19)	.042 (1.07)	.0035 (.0889)
¾ (19)	.875 (22)	.045 (1.14)	.004 (.102)
1 (25)	1.125 (29)	.050 (1.27)	.004 (.102)
1¼ (32)	1.375 (35)	.055 (1.40)	.0045 (.1143)
1½ (38)	1.625 (41)	.060 (1.52)	.0045 (.1143)

(c) Copper pipe used in mains and service lines may not be used at pressures in excess of 100 p.s.i. (689 kPa) gage.

(d) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft^3 (6.9/m^3) under standard conditions. Standard conditions refers to 60 °F and 14.7 psia (15.6 °C and one atmosphere) of gas.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–62, 54 FR 5628, Feb. 6, 1989; Amdt. 192–85, 63 FR 37502, July 13, 1998]

Subpart D—Design of Pipeline Components

§ 192.141 Scope.

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

§ 192.143 General requirements.

(a) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

[Amdt. 48, 49 FR 19824, May 10, 1984, as amended at 72 FR 20059, Apr. 23, 2007]

§ 192.144 Qualifying metallic components.

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in § 192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if—

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in § 192.7 or appendix B of this part:

(1) Pressure testing;

(2) Materials; and

(3) Pressure and temperature ratings.

[Amdt. 192–45, 48 FR 30639, July 5, 1983, as amended by Amdt. 192–94, 69 FR 32894, June 14, 2004]

§ 192.145 Valves.

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Spec 6D (incorporated by reference, *see* § 192.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

(b) Each cast iron and plastic valve must comply with the following:

(1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

(2) The valve must be tested as part of the manufacturing, as follows:

(i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.

(ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.

(iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

(c) Each valve must be able to meet the anticipated operating conditions.

(d) No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if:

(1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i. (7 Mpa) gage; and

(2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(e) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–62, 54 FR 5628, Feb. 6, 1989; Amdt. 192–85, 63 FR 37502, July 13, 1998; Amdt. 192–94, 69 FR 32894, June 14, 2004; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010; Amdt. 192–119, 80 FR 181, Jan. 5, 2015]

§ 192.147 Flanges and flange accessories.

(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B 16.5 and MSS SP–44 (incorporated by reference, *see* § 192.7), or the equivalent.

(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 (incorporated by reference, *see* § 192.7)and be cast integrally with the pipe, valve, or fitting.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192–119, 80 FR 181, Jan. 5, 2015]

§ 192.149 Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

§ 192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

(b) This section does not apply to: (1) Manifolds;

(2) Station piping such as at compressor stations, meter stations, or regulator stations;

(3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

(4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

(7) Offshore transmission lines, except transmission lines 10¾ inches (273 millimeters) or more in outside diameter on which construction begins after December 28, 2005, that run from platform to platform or platform to shore unless—

(i) Platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices; or

(ii) If the design includes taps for lateral connections, the operator can demonstrate, based on investigation or experience, that there is no reasonably practical alternative under the design circumstances to the use of a tap that will obstruct the passage of instrumented internal inspection devices; and

(8) Other piping that, under § 190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

(c) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (a) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under § 190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

[Amdt. 192–72, 59 FR 17281, Apr. 12, 1994, as amended by Amdt. 192–85, 63 FR 37502, July 13, 1998; Amdt. 192–97, 69 FR 36029, June 28, 2004]

§ 192.151 Tapping.

(a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that

(1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

(2) A 1¼-inch (32 millimeters) tap may be made in a 4-inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch (152 millimeters) or larger pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37502, July 13, 1998]

§ 192.153 Components fabricated by welding.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG–101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, *see* § 192.7).

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

(1) Regularly manufactured butt-welding fittings.

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

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

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

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with the ASME BPVC (Section VIII, Division 1 or 2), flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage or more, or is more than 3 inches in (76 millimeters) nominal diameter.

(e) A component having a design pressure established in accordance with paragraph (a) or paragraph (b) of this section and subject to the strength testing requirements of § 192.505(b) must be tested to at least 1.5 times the MAOP.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–1, 35 FR 17660, Nov. 17, 1970; 58 FR 14521, Mar. 18, 1993; Amdt. 192–68, 58 FR 45268, Aug. 27, 1993; Amdt. 192–85, 63 FR 37502, July 13, 1998; Amdt. 192–119, 80 FR 181, Jan. 5, 2015; Amdt. 192–120, 80 FR 12778, Mar. 11, 2015; Amdt. 192–119, 80 FR 46847, Aug. 6, 2015]

§ 192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§ 192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§ 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.163 Compressor stations: Design and construction.

(a) *Location of compressor building.* Except for a compressor building on a platform located offshore or in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

(b) *Building construction.* Each building on a compressor station site must be made of noncombustible materials if it contains either—

(1) Pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or

(2) Gas handling equipment other than gas utilization equipment used for domestic purposes.

(c) *Exits.* Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

(d) *Fenced areas.* Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

(e) *Electrical facilities.* Electrical equipment and wiring installed in compressor stations must conform to the NFPA–70, so far as that code is applicable.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–27, 41 FR 34605, Aug. 16, 1976; Amdt. 192–37, 46 FR 10159, Feb. 2, 1981; 58 FR 14521, Mar. 18, 1993; Amdt. 192–85, 63 FR 37502, 37503, July 13, 1998; Amdt. 192–119, 80 FR 181, Jan. 5, 2015]

§ 192.165 Compressor stations: Liquid removal.

(a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

(b) Each liquid separator used to remove entrained liquids at a compressor station must:

(1) Have a manually operable means of removing these liquids.

(2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and

(3) Be manufactured in accordance with section VIII ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, *see* § 192.7) and the additional requirements of § 192.153(e) except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–119, 80 FR 181, Jan. 5, 2015; Amdt. 192–120, 80 FR 12778, Mar. 11, 2015]

§ 192.167 Compressor stations: Emergency shutdown.

(a) Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:

(1) It must be able to block gas out of the station and blow down the station piping.

(2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.

(3) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except that:

(i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and

(ii) Electrical circuits needed to protect equipment from damage may remain energized.

(4) It must be operable from at least two locations, each of which is:

(i) Outside the gas area of the station;

(ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and

(iii) Not more than 500 feet (153 meters) from the limits of the station.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

(1) In the case of an unattended compressor station:

(i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or

(ii) When an uncontrolled fire occurs on the platform; and

(2) In the case of a compressor station in a building:

(i) When an uncontrolled fire occurs in the building; or

(ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition.

For the purpose of paragraph (c)(2)(ii) of this section, an electrical facility which conforms to Class 1, Group D, of the National Electrical Code is not a source of ignition.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–27, 41 FR 34605, Aug. 16, 1976; Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.169 Compressor stations: Pressure limiting devices.

(a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.

(b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

§ 192.171 Compressor stations: Additional safety equipment.

(a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

(b) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

(c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

(d) Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

(e) Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

§ 192.173 Compressor stations: Ventilation.

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

§ 192.175 Pipe-type and bottle-type holders.

(a) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

C = (3D*P*F)/1000) in inches; (C = (3D*P*F*)/6,895) in millimeters

in which:

C = Minimum clearance between pipe containers or bottles in inches (millimeters).
D = Outside diameter of pipe containers or bottles in inches (millimeters).
P = Maximum allowable operating pressure, psi (kPa) gauge.
F = Design factor as set forth in § 192.111 of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–123, 82 FR 7997, Jan. 23, 2017]

§ 192.177 Additional provisions for bottle-type holders.

(a) Each bottle-type holder must be—

(1) Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum allowable operating pressure	Minimum clearance feet (meters)
Less than 1,000 p.s.i. (7 MPa) gage	25 (7.6)
1,000 p.s.i. (7 MPa) gage or more	100 (31)

(2) Designed using the design factors set forth in § 192.111; and

(3) Buried with a minimum cover in accordance with § 192.327.

(b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

(1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/372M (incorporated by reference, *see* § 192.7).

(2) The actual yield-tensile ratio of the steel may not exceed 0.85.

(3) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small

diameter portion of the bottle end closure for cathodic protection if a localized thermit welding process is used.

(4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.

(5) The holder, connection pipe, and components must be leak tested after installation as required by subpart J of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–58, 53 FR 1635, Jan. 21, 1988; Amdt. 192–62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–119, 80 FR 181, Jan. 5, 2015]

§ 192.179 Transmission line valves.

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

(1) Each point on the pipeline in a Class 4 location must be within 2½ miles (4 kilometers)of a valve.

(2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.

(3) Each point on the pipeline in a Class 2 location must be within 7½ miles (12 kilometers) of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

(d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–27, 41 FR 34606, Aug. 16, 1976; Amdt. 192–78, 61 FR 28784, June 6, 1996; Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.181 Distribution line valves.

(a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

(1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

(2) The operating stem or mechanism must be readily accessible.

(3) If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§ 192.183 Vaults: Structural design requirements.

(a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

(b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inch (254 millimeters), and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.185 Vaults: Accessibility.

Each vault must be located in an accessible location and, so far as practical, away from:

(a) Street intersections or points where traffic is heavy or dense;

(b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and

(c) Water, electric, steam, or other facilities.

§ 192.187 Vaults: Sealing, venting, and ventilation.

Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows:

(a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):

(1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;

(2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

(3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

(b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):

(1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;

(2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

(3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

(c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.189 Vaults: Drainage and waterproofing.

(a) Each vault must be designed so as to minimize the entrance of water.

(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

(c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, NFPA–70 (incorporated by reference, *see* § 192.7).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–76, 61 FR 26122, May 24, 1996; Amdt. 192–119, 80 FR 181, Jan. 5, 2015]

§ 192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517, (incorporated by reference, *see* § 192.7).

(b) Thermoplastic fittings for plastic pipe must conform to ASTM D2513–99 for plastic materials other than polyethylene or ASTM D2513–09a for polyethylene plastic materials.

[Amdt. 192–114, 75 FR 48603, Aug. 11, 2010, as amended by Amdt. 192–119, 80 FR 181, Jan. 5, 2015]

§ 192.193 Valve installation in plastic pipe.

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

§ 192.195 Protection against accidental overpressuring.

(a) *General requirements.* Except as provided in § 192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§ 192.199 and 192.201.

(b) *Additional requirements for distribution systems.* Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

(1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

(2) Be designed so as to prevent accidental overpressuring.

§ 192.197 Control of the pressure of gas delivered from high-pressure distribution systems.

(a) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less and a service regulator having the following characteristics is used, no other pressure limiting device is required:

(1) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.

(2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

(3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.

(4) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.

(5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(6) A self-contained service regulator with no external static or control lines.

(b) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

(1) A service regulator having the characteristics listed in paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i. (414 kPa) gage. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i. (414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i. (414 kPa) gage or less), and remains closed until manually reset.

(2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed

the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i. (862 kPa) gage. For higher inlet pressures, the methods in paragraph (c) (1) or (2) of this section must be used.

(4) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 7, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§ 192.199 Requirements for design of pressure relief and limiting devices.

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:

(i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

(ii) If the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. (41 kPa) gage; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–9, 37 FR 20827, Oct. 4, 1972; Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.203 Instrument, control, and sampling pipe and components.

(a) *Applicability.* This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

(b) *Materials and design.* All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

(1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

(2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

(3) Brass or copper material may not be used for metal temperatures greater than 400 °F (204 °C).

(4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

(7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

(8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

(9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–78, 61 FR 28784, June 6, 1996; Amdt. 192–85, 63 FR 37503, July 13, 1998]

Subpart E—Welding of Steel in Pipelines

§ 192.221 Scope.

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines.

(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

§ 192.225 Welding procedures.

(a) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, *see* § 192.7), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, *see* § 192.7) to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify welding procedures must be determined by destructive testing in accordance with the applicable welding standard(s).

(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

[Amdt. 192–52, 51 FR 20297, June 4, 1986; Amdt. 192–94, 69 FR 32894, June 14, 2004; Amdt. 192–119, 80 FR 181, Jan. 5, 2015; Amdt. 192–120, 80 FR 12778, Mar. 11, 2015; Amdt. 192–123, 82 FR 7997, Jan. 23, 2017]

§ 192.227 Qualification of welders and welding operators.

(a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, *see* § 192.7), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, *see* § 192.7). However, a welder or welding operator qualified under an earlier edition than the listed in § 192.7 of this part may weld but may not requalify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

[Amdt. 192–120, 80 FR 12778, Mar. 11, 2015, as amended by Amdt. 192–123, 82 FR 7997, Jan. 23, 2017]

§ 192.229 Limitations on welders and welding operators.

(a) No welder or welding operator whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(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.

(c) A welder or welding operator qualified under § 192.227(a)—

(1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder or welding operator has had one weld tested and found acceptable under either section 6, section 9, section 12 or Appendix A of API Std 1104 (incorporated by reference, *see* § 192.7). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7½ months. A welder or welding operator qualified under an earlier edition of a standard listed in § 192.7 of this part may weld, but may not re-qualify under that earlier edition; and,

(2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder or welding operator is tested in accordance with paragraph (c)(1) of this section or re-qualifies under paragraph (d)(1) or (d)(2) of this section.

(d) A welder or welding operator qualified under § 192.227(b) may not weld unless—

(1) Within the preceding 15 calendar months, but at least once each calendar year, the welder or welding operator has re-qualified under § 192.227(b); or

(2) Within the preceding 7½ calendar months, but at least twice each calendar year, the welder or welding operator has had—

(i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(ii) For a welder who works only on service lines 2 inches (51 millimeters) or smaller in diameter, the welder has had two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

[Amdt. 192–120, 80 FR 12778, Mar. 11, 2015]

§ 192.231 Protection from weather.

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

§ 192.233 Miter joints.

(a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.

(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 12½° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

(c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

§ 192.235 Preparation for welding.

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

§ 192.241 Inspection and test of welds.

(a) Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that:

(1) The welding is performed in accordance with the welding procedure; and

(2) The weld is acceptable under paragraph (c) of this section.

(b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with § 192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:

(1) The pipe has a nominal diameter of less than 6 inches (152 millimeters); or

(2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 9 or Appendix A of API Std 1104 (incorporated by reference, *see* § 192.7). Appendix A of API Std 1104 may not be used to accept cracks.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–37, 46 FR 10160, Feb. 2, 1981; Amdt. 192–78, 61 FR 28784, June 6, 1996; Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–94, 69 FR 32894, June 14, 2004; Amdt. 192–119, 80 FR 181, Jan. 5, 2015; Amdt. 192–120, 80 FR 12778, Mar. 11, 2015]

§ 192.243 Nondestructive testing.

(a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.

(b) Nondestructive testing of welds must be performed:

(1) In accordance with written procedures; and

(2) By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under § 192.241(c).

(d) When nondestructive testing is required under § 192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

(1) In Class 1 locations, except offshore, at least 10 percent.

(2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

(4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

(e) Except for a welder or welding operator whose work is isolated from the principal welding activity, a sample of each welder or welding operator's work for each day must be nondestructively tested, when nondestructive testing is required under § 192.241(b).

(f) When nondestructive testing is required under § 192.241(b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–27, 41 FR 34606, Aug. 16, 1976; Amdt. 192–50, 50 FR 37192, Sept. 12, 1985; Amdt. 192–78, 61 FR 28784, June 6, 1996; Amdt. 192–120, 80 FR 12779, Mar. 11, 2015]

§ 192.245 Repair or removal of defects.

(a) Each weld that is unacceptable under § 192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

(b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

(c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under § 192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

[Amdt. 192–46, 48 FR 48674, Oct. 20, 1983]

Subpart F—Joining of Materials Other Than by Welding

§ 192.271 Scope.

(a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.

(b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.

§ 192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

§ 192.275 Cast iron pipe.

(a) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

(b) Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

(c) Cast iron pipe may not be joined by threaded joints.

(d) Cast iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–62, 54 FR 5628, Feb. 6, 1989]

§ 192.277 Ductile iron pipe.

(a) Ductile iron pipe may not be joined by threaded joints.

(b) Ductile iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–62, 54 FR 5628, Feb. 6, 1989]

§ 192.279 Copper pipe.

Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

[Amdt. 192–62, 54 FR 5628, Feb. 6, 1989, as amended at 58 FR 14521, Mar. 18, 1993]

§ 192.281 Plastic pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM D2513–99, (incorporated by reference, *see* § 192.7).

(3) The joint may not be heated to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of § 192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints.* Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM D 2517 (incorporated by reference, *see* § 192.7).

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–34, 44 FR 42973, July 23, 1979; Amdt. 192–58, 53 FR 1635, Jan. 21, 1988; Amdt. 192–61, 53 FR 36793, Sept. 22, 1988; 58 FR 14521, Mar. 18, 1993; Amdt. 192–78, 61 FR 28784, June 6, 1996; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010; Amdt. 192–119, 80 FR 181, Jan. 5, 2015]

§ 192.283 Plastic pipe: Qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under § 192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) of ASTM D2513–99 for plastic materials other than polyethylene or ASTM D2513–09a (incorporated by reference, *see* § 192.7) for polyethylene plastic materials;

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517 (incorporated by reference, *see* § 192.7); or

(iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055 (incorporated by reference, see § 192.7).

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for non-láteral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference, *see* § 192.7), except that the test may be conducted at ambient temperature and humidity If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical joints.* Before any written procedure established under § 192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D 638 (except for conditioning), (incorporated by reference, *see* § 192.7).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 0.20 in (5.0 mm) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 4 inches (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 °F (38 °C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

[Amdt. 192–34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192–34B, 46 FR 39, Jan. 2, 1981; 47 FR 32720, July 29, 1982; 47 FR 49973, Nov. 4, 1982; 58 FR 14521, Mar. 18, 1993; Amdt. 192–78, 61 FR 28784, June 6, 1996; Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–94, 69 FR 32895, June 14, 2004; Amdt. 192–94, 69 FR 54592, Sept. 9, 2004; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010; Amdt. 192–119, 80 FR 181, Jan. 5, 2015]

§ 192.285 Plastic pipe: Qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:

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

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

(i) Tested under any one of the test methods listed under § 192.283(a) applicable to the type of joint and material being tested;

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

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

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

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

(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under § 192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.

[Amdt. 192–34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192–34B, 46 FR 39, Jan. 2, 1981; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003; Amdt. 192–120, 80 FR 12779, Mar. 11, 2015]

§ 192.287 Plastic pipe: Inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by §§ 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

[Amdt. 192–34, 44 FR 42974, July 23, 1979]

Subpart G—General Construction Requirements for Transmission Lines and Mains

§ 192.301 Scope.

This subpart prescribes minimum requirements for constructing transmission lines and mains.

§ 192.303 Compliance with specifications or standards.

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

§ 192.305 Inspection: General.

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

EFFECTIVE DATE NOTE: At 80 FR 12779, Mar. 11, 2015, § 192.305 was revised, effective Oct. 1, 2015. At 80 FR 58633, Sept. 30, 2015, this amendment was delayed indefinitely. For the convenience of the user, the revised text is set forth as follows:

§ 192.305 Inspection: General.

Each transmission line and main must be inspected to ensure that it is constructed in accordance with this subpart. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

§ 192.307 Inspection of materials.

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

§ 192.309 Repair of steel pipe.

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

(1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.

(2) A dent that affects the longitudinal weld or a circumferential weld.

(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

(i) More than ¼ inch (6.4 millimeters) in pipe 12¾ inches (324 millimeters) or less in outer diameter; or

(ii) More than 2 percent of the nominal pipe diameter in pipe over 12¾ inches (324 millimeters) in outer diameter.

For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

(e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–1, 35 FR 17660, Nov. 17, 1970; Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–88, 64 FR 69664, Dec. 14, 1999]

§ 192.311 Repair of plastic pipe.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed.

[Amdt. 192–93, 68 FR 53900, Sept. 15, 2003]

§ 192.313 Bends and elbows.

(a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with § 192.315, must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.

(b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

(c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).

[Amdt. 192–26, 41 FR 26018, June 24, 1976, as amended by Amdt. 192–29, 42 FR 42866, Aug. 25, 1977; Amdt. 192–29, 42 FR 60148, Nov. 25, 1977; Amdt. 192–49, 50 FR 13225, Apr. 3, 1985; Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.315 Wrinkle bends in steel pipe.

(a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.

(b) Each wrinkle bend on steel pipe must comply with the following:

(1) The bend must not have any sharp kinks.

(2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.

(3) On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than 1½° for each wrinkle.

(4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.317 Protection from hazards.

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

[Amdt. 192–27, 41 FR 34606, Aug. 16, 1976, as amended by Amdt. 192–78, 61 FR 28784, June 6, 1996]

§ 192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:

(1) Provides firm support under the pipe; and

(2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–27, 41 FR 34606, Aug. 16, 1976; Amdt. 192–78, 61 FR 28784, June 6, 1996; Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level except as provided by paragraphs (g) and (h) of this section.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inch (2.29 millimeters), except that pipe with an outside diameter of 0.875 inch (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inch (1.58 millimeters).

(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

(g) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

(1) The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

(2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

(3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

(h) Plastic pipe may be installed on bridges provided that it is:

(1) Installed with protection from mechanical damage, such as installation in a metallic casing;

(2) Protected from ultraviolet radiation; and

(3) Not allowed to exceed the pipe temperature limits specified in § 192.123.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–78, 61 FR 28784, June 6, 1996; Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003; Amdt. 192–94, 69 FR 32895, June 14, 2004]

§ 192.323 Casing.

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

§ 192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in § 192.175(b).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.327 Cover.

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal soil	Consolidated rock
Inches (Millimeters).		
Class 1 locations	30 (762)	18 (457)
Class 2, 3, and 4 locations	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings	36 (914)	24 (610)

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:

(1) Establishes a minimum cover of less than 24 inches (610 millimeters);

(2) Requires that mains be installed in a common trench with other utility lines; and

(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in § 192.3, must be installed in accordance with § 192.612(b)(3).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-98, 69 FR 48406, Aug. 10, 2004]

§ 192.328 Additional construction requirements for steel pipe using alternative maximum allowable operating pressure.

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure calculated under § 192.620, a segment must meet the following additional construction requirements. Records must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this construction issue:	The pipeline segment must meet this additional construction requirement:
(a) Quality assurance	(1) The construction of the pipeline segment must be done under a quality assurance plan addressing pipe inspection, hauling and stringing, field bending, welding, non-destructive examination of girth welds, applying and testing field applied coating, lowering of the pipeline into the ditch, padding and backfilling, and hydrostatic testing. (2) The quality assurance plan for applying and testing field applied coating to girth welds must be: (i) Equivalent to that required under § 192.112(f)(3) for pipe; and (ii) Performed by an individual with the knowledge, skills, and ability to assure effective coating application.
(b) Girth welds	(1) All girth welds on a new pipeline segment must be non-destructively examined in accordance with § 192.243(b) and (c).
(c) Depth of cover	(1) Notwithstanding any lesser depth of cover otherwise allowed in § 192.327, there must be at least 36 inches (914 millimeters) of cover or equivalent means to protect the pipeline from outside force damage. (2) In areas where deep tilling or other activities could threaten the pipeline, the top of the pipeline must be installed at least one foot below the deepest expected penetration of the soil.
(d) Initial strength testing	(1) The pipeline segment must not have experienced failures indicative of systemic material defects during strength testing, including initial hydrostatic testing. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic concern. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipe is in service at least 60 days prior to operating at the alternative MAOP. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.
(e) Interference currents	(1) For a new pipeline segment, the construction must address the impacts of induced alternating current from parallel electric transmission lines and other known sources of potential interference with corrosion control.

[72 FR 62176, Oct. 17, 2008]

Subpart H—Customer Meters, Service Regulators, and Service Lines

§ 192.351 Scope.

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

§ 192.353 Customer meters and regulators: Location.

(a) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried.

(b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

(c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter.

(d) Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003]

§ 192.355 Customer meters and regulators: Protection from damage.

(a) *Protection from vacuum or back pressure.* If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.

(b) *Service regulator vents and relief vents.* Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must—

(1) Be rain and insect resistant;

(2) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

(3) Be protected from damage caused by submergence in areas where flooding may occur.

(c) *Pits and vaults.* Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–58, 53 FR 1635, Jan. 21, 1988]

§ 192.357 Customer meters and regulators: Installation.

(a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

(b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.

(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

§ 192.359 Customer meter installations: Operating pressure.

(a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure.

(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i. (69 kPa) gage.

(c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–1, 35 FR 17660, Nov. 17, 1970; Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.361 Service lines: Installation.

(a) *Depth.* Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) *Support and backfill.* Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) *Grading for drainage.* Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) *Protection against piping strain and external loading.* Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) *Installation of service lines into buildings.* Each underground service line installed below grade through the outer foundation wall of a building must:

(1) In the case of a metal service line, be protected against corrosion;

(2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and

(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) *Installation of service lines under buildings.* Where an underground service line is installed under a building:

(1) It must be encased in a gas tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend

above grade, terminating in a rain and insect resistant fitting.

(g) *Locating underground service lines.* Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with § 192.321(e).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–75, 61 FR 18517, Apr. 26, 1996; Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003]

§ 192.363 Service lines: Valve requirements.

(a) Each service line must have a service-line valve that meets the applicable requirements of subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

§ 192.365 Service lines: Location of valves.

(a) *Relation to regulator or meter.* Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

(b) *Outside valves.* Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) *Underground valves.* Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

§ 192.367 Service lines: General requirements for connections to main piping.

(a) *Location.* Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

(b) *Compression-type connection to main.* Each compression-type service line to main connection must:

(1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

(2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–75, 61 FR 18517, Apr. 26, 1996]

§ 192.369 Service lines: Connections to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of § 192.273.

(b) If a threaded tap is being inserted, the requirements of § 192.151 (b) and (c) must also be met.

§ 192.371 Service lines: Steel.

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

[Amdt. 192–1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.373 Service lines: Cast iron and ductile iron.

(a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37503, July 13, 1998]

§ 192.375 Service lines: Plastic.

(a) Each plastic service line outside a building must be installed below ground level, except that—

(1) It may be installed in accordance with § 192.321(g); and

(2) It may terminate above ground level and outside the building, if—

(i) The above ground level part of the plastic service line is protected against deterioration and external damage; and

(ii) The plastic service line is not used to support external loads.

(b) Each plastic service line inside a building must be protected against external damage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–78, 61 FR 28785, June 6, 1996]

§ 192.377 Service lines: Copper.

Each copper service line installed within a building must be protected against external damage.

§ 192.379 New service lines not in use.

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

(a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

[Amdt. 192–8, 37 FR 20694, Oct. 3, 1972]

§ 192.381 Service lines: Excess flow valve performance standards.

(a) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 p.s.i. (69 kPa) gage:

(i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

(ii) Upon closure, reduce gas flow—

(A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

(B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

(b) An excess flow valve must meet the applicable requirements of Subparts B and D of this part.

(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

(d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

(e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

[Amdt. 192–79, 61 FR 31459, June 20, 1996, as amended by Amdt. 192–80, 62 FR 2619, Jan. 17, 1997; Amdt. 192–85, 63 FR 37504, July 13, 1998; Amdt. 192–121, 81 FR 71001, Oct. 14, 2016]

§ 192.383 Excess flow valve installation.

(a) *Definitions.* As used in this section:

Branched service line means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

Replaced service line means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence (SFR).

(b) *Installation required.* An EFV installation must comply with the performance standards in § 192.381. After April 14, 2017, each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated:

(1) A single service line to one SFR;

(2) A branched service line to a SFR installed concurrently with the primary SFR service line (*i.e.*, a single EFV may be installed to protect both service lines);

(3) A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV;

(4) Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation based on installed meter capacity, and

(5) A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity.

(c) *Exceptions to excess flow valve installation requirement.* An operator need not install an excess flow valve if one or more of the following conditions are present:

(1) The service line does not operate at a pressure of 10 psig or greater throughout the year;

(2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a customer;

(3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

(4) An EFV meeting the performance standards in § 192.381 is not commercially available to the operator.

(d) *Customer's right to request an EFV.* Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one of the exceptions in paragraph (c) of this section may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.

(e) *Operator notification of customers concerning EFV installation.* Operators must notify customers of their right to request an EFV in the following manner:

(1) Except as specified in paragraphs (c) and (e)(5) of this section, each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, Web site postings, and e-billing notices.

(2) The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks.

(3) The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known.

(4) The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of paragraph (c) are not present, the operator must install an EFV at a mutually agreeable date.

(5) Operators of master-meter systems and liquefied petroleum gas (LPG) operators with fewer than 100 customers may continuously post a

general notification in a prominent location frequented by customers.

(f) *Operator evidence of customer notification*. An operator must make a copy of the notice or notices currently in use available during PHMSA inspections or State inspections conducted under a pipeline safety program certified or approved by PHMSA under 49 U.S.C. 60105 or 60106.

(g) *Reporting*. Except for operators of master-meter systems and LPG operators with fewer than 100 customers, each operator must report the EFV measures detailed in the annual report required by § 191.11.

[Amdt. 192–121, 81 FR 71001, Oct. 14, 2016; 81 FR 72739, Oct. 21, 2016]

§ 192.385 Manual service line shut-off valve installation.

(a) *Definitions*. As used in this section:

Manual service line shut-off valve means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.

(b) *Installation requirement*. The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH.

(c) *Accessibility and maintenance*. Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this section are subject to regular scheduled maintenance, as documented by the operator and consistent with the valve manufacturer's specification.

[Amdt. 192–121, 81 FR 71002, Oct. 14, 2016]

Subpart I—Requirements for Corrosion Control

SOURCE: Amdt. 192–4, 36 FR 12302, June 30, 1971, unless otherwise noted.

§ 192.451 Scope.

(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(b) [Reserved]

[Amdt. 192–4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192–27, 41 FR 34606, Aug. 16, 1976; Amdt. 192–33, 43 FR 39389, Sept. 5, 1978]

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

(a) *Converted pipelines*. Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with § 192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

(b) *Regulated onshore gathering lines*. For any regulated onshore gathering line under § 192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under § 192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

[Amdt. 192–30, 42 FR 60148, Nov. 25, 1977, as amended by Amdt. 192–102, 71 FR 13303, Mar. 15, 2006]

§ 192.453 General.

The corrosion control procedures required by § 192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

[Amdt. 192–71, 59 FR 6584, Feb. 11, 1994]

§ 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of § 192.461.

(2) It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—

(1) For a copper pipeline, a corrosive environment does not exist; or

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a)(2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if:

(1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

[Amdt. 192–4, 36 FR 12302, June 30, 1971, as amended at Amdt. 192–28, 42 FR 35654, July 11, 1977; Amdt. 192–39, 47 FR 9844, Mar. 8, 1982; Amdt. 192–78, 61 FR 28785, June 6, 1996; Amdt. 192–85, 63 FR 37504, July 13, 1998]

§ 192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

(2) Bare or coated pipes at compressor, regulator, and measuring stations.

(3) Bare or coated distribution lines.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§ 192.459 External corrosion control: Examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under §§ 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

[Amdt. 192-87, 64 FR 56981, Oct. 22, 1999]

§ 192.461 External corrosion control: Protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

§ 192.463 External corrosion control: Cathodic protection.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential—

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of appendix D of this part for amphoteric metals.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

§ 192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by §§192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

[Amdt. 192–4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192–33, 43 FR 39390, Sept. 5, 1978; Amdt. 192–35A, 45 FR 23441, Apr. 7, 1980; Amdt. 192–85, 63 FR 37504, July 13, 1998; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003; Amdt. 192–114, 75 FR 48603, Aug. 11, 2010]

§ 192.467 External corrosion control: Electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

[Amdt. 192–4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192–33, 43 FR 39390, Sept. 5, 1978]

§ 192.469 External corrosion control: Test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

[Amdt. 192–27, 41 FR 34606, Aug. 16, 1976]

§ 192.471 External corrosion control: Test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§ 192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m^3) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.476 Internal corrosion control: Design and construction of transmission line.

(a) *Design and construction.* Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

(b) *Exceptions to applicability.* The design and construction requirements of paragraph (a) of this section do not apply to the following:

(1) Offshore pipeline; and

(2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

(c) *Change to existing transmission line.* When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

(d) *Records.* An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

[72 FR 20059, Apr. 23, 2007]

§ 192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months.

[Amdt. 192–33, 43 FR 39390, Sept. 5, 1978]

§ 192.479 Atmospheric corrosion control: General.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

[Amdt. 192–93, 68 FR 53901, Sept. 15, 2003]

§ 192.481 Atmospheric corrosion control: Monitoring.

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

If the pipeline is located:	Then the frequency of inspection is:
Onshore	At least once every 3 calendar years, but with intervals not exceeding 39 months
Offshore	At least once each calendar year, but with intervals not exceeding 15 months

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by § 192.479.

[Amdt. 192–93, 68 FR 53901, Sept. 15, 2003]

§ 192.483 Remedial measures: General.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of § 192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§ 192.485 Remedial measures: Transmission lines.

(a) *General corrosion*. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting*. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, *see* § 192.7) or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, see § 192.7). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-88, 64 FR 69664, Dec. 14, 1999; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.487 Remedial measures: Distribution lines other than cast iron or ductile iron lines.

(a) *General corrosion.* Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-88, 64 FR 69665, Dec. 14, 1999]

§ 192.489 Remedial measures: Cast iron and ductile iron pipelines.

(a) *General graphitization.* Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.

(b) *Localized graphitization.* Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

§ 192.490 Direct assessment.

Each operator that uses direct assessment as defined in § 192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard [1]
External corrosion	§ 192.925 [2]
Internal corrosion in pipelines that transport dry gas.	§ 192.927
Stress corrosion cracking	§ 192.929

[1] For lines not subject to subpart O of this part, the terms "covered segment" and "covered pipeline segment" in §§ 192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.

[2] In § 192.925(b), the provision regarding detection of coating damage applies only to pipelines subject to subpart O of this part.

[Amdt. 192-101, 70 FR 61575, Oct. 25, 2005]

§ 192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§ 192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

[Amdt. 192–78, 61 FR 28785, June 6, 1996]

Subpart J—Test Requirements

§ 192.501 Scope.

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

§ 192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

(1) It has been tested in accordance with this subpart and § 192.619 to substantiate the maximum allowable operating pressure; and

(2) Each potentially hazardous leak has been located and eliminated.

(b) The test medium must be liquid, air, natural gas, or inert gas that is—

(1) Compatible with the material of which the pipeline is constructed;

(2) Relatively free of sedimentary materials; and

(3) Except for natural gas, nonflammable.

(c) Except as provided in § 192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

(e) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that:

(1) The component was tested to at least the pressure required for the pipeline to which it is being added;

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

(3) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in § 192.143.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–58, 53 FR 1635, Jan. 21, 1988; Amdt. 192–60, 53 FR 36029, Sept. 16, 1988; Amdt. 192–60A, 54 FR 5485, Feb. 3, 1989; Amdt. 192–120, 80 FR 12779, Mar. 11, 2015]

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

(a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet (91 meters) of such a building, but in no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.

(b) In a Class 1 or Class 2 location, each compressor station regulator station, and measuring station, must be tested to at least Class 3 location test requirements.

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

(d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37504, July 13, 1998; Amdt. 192–94, 69 FR 32895, June 14, 2004; Amdt. 195–94, 69 FR 54592, Sept. 9, 2004; Amdt. 192–120, 80 FR 12779, Mar. 11, 2015]

§ 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.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium—

(1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or

(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.

(c) The pressure must be maintained at or above the test pressure for at least 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–58, 53 FR 1635, Jan. 21, 1988; Amdt. 192–85, 63 FR 37504, July 13, 1998]

§ 192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:

(a) The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) Each main that is to be operated at less than 1 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–58, 53 FR 1635, Jan. 21, 1988; Amdt. 192–85, 63 FR 37504, July 13, 1998]

§ 192.511 Test requirements for service lines.

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (6.9 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i. (276 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with § 192.507 of this subpart.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–74, 61 FR 18517, Apr. 26, 1996; Amdt. 192–85, 63 FR 37504, July 13, 1998]

§ 192.513 Test requirements for plastic pipelines.

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 p.s.i. (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than three times the pressure determined under § 192.121, at a temperature not less than the pipe temperature during the test.

(d) During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–77, 61 FR 27793, June 3, 1996; 61 FR 45905, Aug. 30, 1996; Amdt. 192–85, 63 FR 37504, July 13, 1998]

§ 192.515 Environmental protection and safety requirements.

(a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

§ 192.517 Records.

(a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505 and 192.507. The record must contain at least the following information:

(1) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.

(2) Test medium used.

(3) Test pressure.

(4) Test duration.

(5) Pressure recording charts, or other record of pressure readings.

(6) Elevation variations, whenever significant for the particular test.

(7) Leaks and failures noted and their disposition.

(b) Each operator must maintain a record of each test required by §§ 192.509, 192.511, and 192.513 for at least 5 years.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–93, 68 FR 53901, Sept. 15, 2003]

Subpart K—Uprating

§ 192.551 Scope.

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

§ 192.553 General requirements.

(a) *Pressure increases.* Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

(1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

(2) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

(b) *Records.* Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.

(c) *Written plan.* Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.

(d) *Limitation on increase in maximum allowable operating pressure.* Except as provided in § 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under §§ 192.619 and 192.621 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, the MAOP may be increased as provided in § 192.619(a)(1).

[35 FR 13257, Aug. 10, 1970, as amended by Amdt. 192–78, 61 FR 28785, June 6, 1996; Amdt. 192–93, 68 FR 53901, Sept. 15, 2003]

§ 192.555 Uprating to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.

(a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall:

(1) Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this part; and

(2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

(c) After complying with paragraph (b) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under § 192.619, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

(d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:

(1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.

(2) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if:

(i) It is impractical to test it in accordance with the requirements of this part;

(ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

(iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this part.

(e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d)(2) of this section, the increase in pressure must be made in increments that are equal to:

(1) 10 percent of the pressure before the uprating; or

(2) 25 percent of the total pressure increase,

whichever produces the fewer number of increments.

§ 192.557 Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

(a) Unless the requirements of this section have been met, no person may subject:

(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or

(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

(1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need

not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;

(3) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

(4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation;

(5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

(6) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.

(c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i. (69 kPa) gage or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.

(d) If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

(1) In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill.

(2) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and shall use the greatest cover measured.

(3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Pipe size inches (millimeters)	Allowance inches (millimeters)		
	Cast iron pipe		Ductile iron pipe
	Pit cast pipe	Centrifugally cast pipe	
3 to 8 (76 to 203)	0.075 (1.91)	0.065 (1.65)	0.065 (1.65)
10 to 12 (254 to 305)	0.08 (2.03)	0.07 (1.78)	0.07 (1.78)
14 to 24 (356 to 610)	0.08 (2.03)	0.08 (2.03)	0.075 (1.91)
30 to 42 (762 to 1067)	0.09 (2.29)	0.09 (2.29)	0.075 (1.91)
48 (1219)	0.09 (2.29)	0.09 (2.29)	0.08 (2.03)
54 to 60 (1372 to 1524)	0.09 (2.29)	....	....

(4) For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 p.s.i. (76 MPa) gage and a modulus of rupture of 31,000 p.s.i. (214 MPa) gage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–37, 46 FR 10160, Feb. 2, 1981; Amdt. 192–62, 54 FR 5628, Feb. 6, 1989; Amdt. 195–85, 63 FR 37504, July 13, 1998]

Subpart L—Operations

§ 192.601 Scope.

This subpart prescribes minimum requirements for the operation of pipeline facilities.

§ 192.603 General provisions.

(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.

(b) Each operator shall keep records necessary to administer the procedures established under § 192.605.

(c) The Associate Administrator or the State Agency that has submitted a current certification under the pipeline safety laws, (49 U.S.C. 60101 *et seq.*) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–66, 56 FR 31090, July 9, 1991; Amdt. 192–71, 59 FR 6584, Feb. 11, 1994; Amdt. 192–75, 61 FR 18517, Apr. 26, 1996; Amdt. 192–118, 78 FR 58915, Sept. 25, 2013]

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

(a) *General.* Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part.

(2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

(3) Making construction records, maps, and operating history available to appropriate operating personnel.

(4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner.

(5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.

(6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

(7) Starting, operating and shutting down gas compressor units.

(8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.

(9) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

(10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including—

(i) Provision for detecting external corrosion before the strength of the container has been impaired;

(ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

(iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

(11) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under § 192.615(a)(3) specifically apply to these reports.

(12) Implementing the applicable control room management procedures required by § 192.631.

(c) *Abnormal operation.* For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i) Unintended closure of valves or shutdowns;

(ii) Increase or decrease in pressure or flow rate outside normal operating limits;

(iii) Loss of communications;

(iv) Operation of any safety device; and

(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Notifying responsible operator personnel when notice of an abnormal operation is received.

(4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

(5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.

(d) *Safety-related condition reports.* The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of § 191.23 of this subchapter.

(e) *Surveillance, emergency response, and accident investigation.* The procedures required by §§ 192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

[Amdt. 192–71, 59 FR 6584, Feb. 11, 1994, as amended by Amdt. 192–71A, 60 FR 14381, Mar. 17, 1995; Amdt. 192–93, 68 FR 53901, Sept. 15, 2003; Amdt. 192–112, 74 FR 63327, Dec. 3, 2009]

§ 192.607 [Reserved]

§ 192.609 Change in class location: Required study.

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) The present class location for the segment involved.

(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.

(c) The physical condition of the segment to the extent it can be ascertained from available records;

(d) The operating and maintenance history of the segment;

(e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

§ 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per § 192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(iii) For pipeline operating at an alternative maximum allowable operating pressure per § 192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§ 192.553 and 192.555.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under § 192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

[Amdt. 192-63A, 54 FR 24174, June 6, 1989, as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-94, 69 FR 32895, June 14, 2004; 73 FR 62177, Oct. 17, 2008]

§ 192.612 Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.

(a) Each operator shall prepare and follow a procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. The procedures must be in effect August 10, 2005.

(b) Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk.

(c) If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall—

(1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1–800–424–8802, of the location and, if available, the geographic coordinates of that pipeline.

(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and

(3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year of discovery, bury the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) for normal excavation or 18 inches (457 millimeters) for rock excavation.

(i) An operator may employ engineered alternatives to burial that meet or exceed the level of protection provided by burial.

(ii) If an operator cannot obtain required state or Federal permits in time to comply with this section, it must notify OPS; specify whether the required permit is State or Federal; and, justify the delay.

[Amdt. 192–98, 69 FR 48406, Aug. 10, 2004]

§ 192.613 Continuing surveillance.

(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with § 192.619 (a) and (b).

§ 192.614 Damage prevention program.

(a) Except as provided in paragraphs (d) and (e) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purposes of this section, the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations.

(b) An operator may comply with any of the requirements of paragraph (c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) of this section.

(1) The state has adopted a one-call damage prevention program under § 198.37 of this chapter; or

(2) The one-call system:

(i) Is operated in accordance with § 198.39 of this chapter;

(ii) Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and

(iii) Assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.

(2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program:

(i) The program's existence and purpose; and

(ii) How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

(ii) In the case of blasting, any inspection must include leakage surveys.

(d) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines located offshore.

(2) Pipelines, other than those located offshore, in Class 1 or 2 locations until September 20, 1995.

(3) Pipelines to which access is physically controlled by the operator.

(e) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following:

(1) The requirement of paragraph (a) of this section that the damage prevention program be written; and

(2) The requirements of paragraphs (c)(1) and (c)(2) of this section.

[Amdt. 192-40, 47 FR 13824, Apr. 1, 1982, as amended by Amdt. 192-57, 52 FR 32800, Aug. 31, 1987; Amdt. 192-73, 60 FR 14650, Mar. 20, 1995; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt.192-82, 62 FR 61699, Nov. 19, 1997; Amdt. 192-84, 63 FR 38758, July 20, 1998]

§ 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) Fire located near or directly involving a pipeline facility.

(iii) Explosion occurring near or directly involving a pipeline facility.

(iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

(8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.

(9) Safely restoring any service outage.

(10) Beginning action under § 192.617, if applicable, as soon after the end of the emergency as possible.

(11) Actions required to be taken by a controller during an emergency in accordance with § 192.631.

(b) Each operator shall:

(1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.

(2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to:

(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

[Amdt. 192–24, 41 FR 13587, Mar. 31, 1976, as amended by Amdt. 192–71, 59 FR 6585, Feb. 11, 1994; Amdt. 192–112, 74 FR 63327, Dec. 3, 2009]

§ 192.616 Public awareness.

(a) Except for an operator of a master meter or petroleum gas system covered under paragraph (j) of this section, each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference, *see* § 192.7).

(b) The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.

(c) The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

(d) The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

(1) Use of a one-call notification system prior to excavation and other damage prevention activities;

(2) Possible hazards associated with unintended releases from a gas pipeline facility;

(3) Physical indications that such a release may have occurred;

(4) Steps that should be taken for public safety in the event of a gas pipeline release; and

(5) Procedures for reporting such an event.

(e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

(f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.

(g) The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

(h) Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. The operator of a master meter or petroleum gas system covered under paragraph (j) of this section must complete development of its written procedure by June 13, 2008. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate State agency.

(i) The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.

(j) Unless the operator transports gas as a primary activity, the operator of a master meter or petroleum gas system is not required to develop a public awareness program as prescribed in paragraphs (a) through (g) of this section. Instead the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter or petroleum gas system is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:

(1) A description of the purpose and reliability of the pipeline;

(2) An overview of the hazards of the pipeline and prevention measures used;

(3) Information about damage prevention;

(4) How to recognize and respond to a leak; and

(5) How to get additional information.

[Amdt. 192-100, 70 FR 28842, May 19, 2005; 70 FR 35041, June 16, 2005; 72 FR 70810, Dec. 13, 2007]

§ 192.617 Investigation of failures.

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

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

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 12¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

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

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

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than § 192.612) after April 13, 2006. —Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.	March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in § 192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under § 192.620(a).

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.619, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.fdsys.gov*.

§ 192.620 Alternative maximum allowable operating pressure for certain steel pipelines.

(a) *How does an operator calculate the alternative maximum allowable operating pressure?* An operator calculates the alternative maximum allowable operating pressure by using different factors in the same formulas used for calculating maximum allowable operating pressure under § 192.619(a) as follows:

(1) In determining the alternative design pressure under § 192.105, use a design factor determined in accordance with § 192.111(b), (c), or (d) or, if none of these paragraphs apply, in accordance with the following table:

Class location	Alternative design factor (F)
1	0.80
2	0.67
3	0.56

(i) For facilities installed prior to December 22, 2008, for which § 192.111(b), (c), or (d) applies, use the following design factors as alternatives for the factors specified in those paragraphs: § 192.111(b) – 0.67 or less; 192.111(c) and (d) – 0.56 or less.

(ii) [Reserved]

(2) The alternative maximum allowable operating pressure is the lower of the following:

(i) The design pressure of the weakest element in the pipeline segment, determined under subparts C and D of this part.

(ii) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction by a factor determined in the following table:

Class location	Alternative test factor
1	1.25
2	[1] 1.50
3	1.50

[1] For Class 2 alternative maximum allowable operating pressure segments installed prior to December 22, 2008 the alternative test factor is 1.25.

(b) *When may an operator use the alternative maximum allowable operating pressure calculated under paragraph (a) of this section?* An operator may use an alternative maximum allowable operating pressure calculated under paragraph (a) of this section if the following conditions are met:

(1) The pipeline segment is in a Class 1, 2, or 3 location;

(2) The pipeline segment is constructed of steel pipe meeting the additional design requirements in § 192.112;

(3) A supervisory control and data acquisition system provides remote monitoring and control of the pipeline segment. The control provided must include monitoring of pressures and flows, monitoring compressor start-ups and shut-downs, and remote closure of valves per paragraph (d)(3) of this section;

(4) The pipeline segment meets the additional construction requirements described in § 192.328;

(5) The pipeline segment does not contain any mechanical couplings used in place of girth welds;

(6) If a pipeline segment has been previously operated, the segment has not experienced any failure during normal operations indicative of a systemic fault in material as determined by a root cause analysis, including metallurgical examination of the failed pipe. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operation at the alternative MAOP. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and

(7) At least 95 percent of girth welds on a segment that was constructed prior to December 22, 2008, must have been non-destructively examined in accordance with §192.243(b) and (c).

(c) *What is an operator electing to use the alternative maximum allowable operating pressure required to do?* If an operator elects to use the alternative maximum allowable operating pressure calculated under paragraph (a) of this section for a pipeline segment, the operator must do each of the following:

(1) For pipelines already in service, notify the PHMSA pipeline safety regional office where the pipeline is in service of the intention to use the alternative pressure at least 180 days before operating at the alternative MAOP. For new pipelines, notify the PHMSA pipeline safety regional office of planned alternative MAOP design and operation at least 60 days prior to the earliest start date of either pipe manufacturing or construction activities. An operator must also notify the state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement or where an intrastate pipeline is regulated by that state.

(2) Certify, by signature of a senior executive officer of the company, as follows:

(i) The pipeline segment meets the conditions described in paragraph (b) of this section; and

(ii) The operating and maintenance procedures include the additional operating and maintenance requirements of paragraph (d) of this section; and

(iii) The review and any needed program upgrade of the damage prevention program required by paragraph (d)(4)(v) of this section has been completed.

(3) Send a copy of the certification required by paragraph (c)(2) of this section to each PHMSA pipeline safety regional office where the pipeline is in service 30 days prior to operating at the alternative MAOP. An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

(4) For each pipeline segment, do one of the following:

(i) Perform a strength test as described in §192.505 at a test pressure calculated under paragraph (a) of this section or

(ii) For a pipeline segment in existence prior to December 22, 2008, certify, under paragraph (c)(2) of this section, that the strength test performed under §192.505 was conducted at test pressure calculated under paragraph (a) of this section, or conduct a new strength test in accordance with paragraph (c)(4)(i) of this section.

(5) Comply with the additional operation and maintenance requirements described in paragraph (d) of this section.

(6) If the performance of a construction task associated with implementing alternative MAOP that occurs after December 22, 2008, can affect the integrity of the pipeline segment, treat that task as a "covered task", notwithstanding the definition in §192.801(b) and implement the requirements of subpart N as appropriate.

(7) Maintain, for the useful life of the pipeline, records demonstrating compliance with paragraphs (b), (c)(6), and (d) of this section.

(8) A Class 1 and Class 2 location can be upgraded one class due to class changes per §192.611(a). All class location changes from Class 1 to Class 2 and from Class 2 to Class 3 must have

all anomalies evaluated and remediated per: The "original pipeline class grade" § 192.620(d)(11) anomaly repair requirements; and all anomalies with a wall loss equal to or greater than 40 percent must be excavated and remediated. Pipelines in Class 4 may not operate at an alternative MAOP.

(d) *What additional operation and maintenance requirements apply to operation at the alternative maximum allowable operating pressure?* In addition to compliance with other applicable safety standards in this part, if an operator establishes a maximum allowable operating pressure for a pipeline segment under paragraph (a) of this section, an operator must comply with the additional operation and maintenance requirements as follows:

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
(1) Identifying and evaluating threats.	Develop a threat matrix consistent with § 192.917 to do the following: (i) Identify and compare the increased risk of operating the pipeline at the increased stress level under this section with conventional operation; and (ii) Describe and implement procedures used to mitigate the risk.
(2) Notifying the public	(i) Recalculate the potential impact circle as defined in § 192.903 to reflect use of the alternative maximum operating pressure calculated under paragraph (a) of this section and pipeline operating conditions; and (ii) In implementing the public education program required under § 192.616, perform the following: (A) Include persons occupying property within 220 yards of the centerline and within the potential impact circle within the targeted audience; and (B) Include information about the integrity management activities performed under this section within the message provided to the audience.
(3) Responding to an emergency in an area defined as a high consequence area in § 192.903.	(i) Ensure that the identification of high consequence areas reflects the larger potential impact circle recalculated under paragraph (d)(2)(i) of this section. (ii) If personnel response time to mainline valves on either side of the high consequence area exceeds one hour (under normal driving conditions and speed limits) from the time the event is identified in the control room, provide remote valve control through a supervisory control and data acquisition (SCADA) system, other leak detection system, or an alternative method of control. (iii) Remote valve control must include the ability to close and monitor the valve position (open or closed), and monitor pressure upstream and downstream. (iv) A line break valve control system using differential pressure, rate of pressure drop or other widely-accepted method is an acceptable alternative to remote valve control.
(4) Protecting the right-of-way ..	(i) Patrol the right-of-way at intervals not exceeding 45 days, but at least 12 times each calendar year, to inspect for excavation activities, ground movement, wash outs, leakage, or other activities or conditions affecting the safety operation of the pipeline. (ii) Develop and implement a plan to monitor for and mitigate occurrences of unstable soil and ground movement. (iii) If observed conditions indicate the possible loss of cover, perform a depth of cover study and replace cover as necessary to restore the depth of cover or apply alternative means to provide protection equivalent to the originally-required depth of cover. (iv) Use line-of-sight line markers satisfying the requirements of § 192.707(d) except in agricultural areas, large water crossings or swamp, steep terrain, or where prohibited by Federal Energy Regulatory Commission orders, permits, or local law. (v) Review the damage prevention program under § 192.614(a) in light of national consensus practices, to ensure the program provides adequate protection of the right-of-way. Identify the standards or practices considered in the review, and meet or exceed those standards or practices by incorporating appropriate changes into the program. (vi) Develop and implement a right-of-way management plan to protect the pipeline segment from damage due to excavation activities.
(5) Controlling internal corrosion.	(i) Develop and implement a program to monitor for and mitigate the presence of, deleterious gas stream constituents. (ii) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and gas quality monitoring equipment. (iii) Use gas quality monitoring equipment that includes a moisture analyzer, chromatograph, and periodic hydrogen sulfide sampling. (iv) Use cleaning pigs and sample accumulated liquids. Use inhibitors when corrosive gas or liquids are present. (v) Address deleterious gas stream constituents as follows: (A) Limit carbon dioxide to 3 percent by volume; (B) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
	(C) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas, where the hydrogen sulfide is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points. (vi) Review the program at least quarterly based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.
(6) Controlling interference that can impact external corrosion.	(i) Prior to operating an existing pipeline segment at an alternate maximum allowable operating pressure calculated under this section, or within six months after placing a new pipeline segment in service at an alternate maximum allowable operating pressure calculated under this section, address any interference currents on the pipeline segment. (ii) To address interference currents, perform the following: (A) Conduct an interference survey to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected; (B) Analyze the results of the survey; and (C) Take any remedial action needed within 6 months after completing the survey to protect the pipeline segment from deleterious current.
(7) Confirming external corrosion control through indirect assessment.	(i) Within six months after placing the cathodic protection of a new pipeline segment in operation, or within six months after certifying a segment under § 192.620(c)(1) of an existing pipeline segment under this section, assess tha adequacy of the cathodic protection through an indirect method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). (ii) Remediate any construction damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP–0502–2002 (incorporated by reference, see § 192.7). (iii) Within six months after completing the baseline internal inspection required under paragraph (d)(9) of this section, integrate the results of the indirect assessment required under paragraph (d)(7)(i) of this section with the results of the baseline internal inspection and take any needed remedial actions. (iv) For all pipeline segments in high consequence areas, perform periodic assessments as follows: (A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with periodic assessments under subpart O of this part. (B) Locate pipe-to-soil test stations at half-mile intervals within each high consequence area ensuring at least one station is within each high consequence area, if practicable. (C) Integrate the results with those of the baseline and periodic assessments for integrity done under paragraphs (d)(9) and (d)(10) of this section.
(6) Controlling external corrosion through cathodic protection.	(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete remedial action within six months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service demonstrating that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and (ii) After remedial action to address a failed reading, confirm restoration of adequate corrosion control by a close interval survey on either side of the affected test station to the next test station unless the reason for the failed reading is determined to be a rectifier connection or power input problem that can be remediated and otherwise verified. (iii) If the pipeline segment has been in operation, the cathodic protection system on the pipeline segment must have been operational within 12 months of the completion of construction.
(9) Conducting a baseline assessment of integrity.	(i) Except as provided in paragraph (d)(9)(iii) of this section, for a new pipeline segment operating at the new alternative maximum allowable operating pressure, perform a baseline internal inspection of the entire pipeline segment as follows: (A) Assess using a geometry tool after the initial hydrostatic test and backfill and within six months after placing the new pipeline segment in service; and (B) Assess using a high resolution magnetic flux tool within three years after placing the new pipeline segment in service at the alternative maximum allowable operating pressure. (ii) Except as provided in paragraph (d)(9)(iii) of this section, for an existing pipeline segment, perform a baseline internal assessment using a geometry tool and a high resolution magnetic flux tool before, but within two years prior to, raising pressure to the alternative maximum allowable operating pressure as allowed under this section. (iii) If headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portion of a pipeline segment operating st alternative maximum allowable operating pressure cannot accommodate s geometry tool and a high resolution magnetic flux tool, use direct assessment (per § 192.925, § 192.927 and/or § 192.929) or pressure testing (per subpart J of this part) to assess that portion.
(10) Conducting periodic assessments of integrity.	(i) Determine a frequency for subsequent periodic integrity assessmants as if all the alternative maximum allowable operating pressure pipeline segments were covered by subpart O of this part and

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
	(ii) Conduct periodic internal inspections using a high resolution magnetic flux tool on the frequency determined under paragraph (d)(10)(i) of this section, or (iii) Use direct assessment (per § 192.925, § 192.927 and/or § 192.929) or pressure testing (per subpart J of this part) for periodic assessment of a portion of a segment to the extent permitted for a baseline assessment under paragraph (d)(9)(iii) of this section.
(11) Making repairs	(i) Perform the following when evaluating an anomaly: (A) Use the most conservative calculation for determining remaining strength or an alternative validated calculation based on pipe diameter, wall thickness, grade, operating pressure, operating stress level, and operating temperature: and (B) Take into account the tolerances of the tools used for the inspection. (ii) Repair a defect immediately if any of the following apply: (A) The defect is a dent discovered during the baseline assessment for integrity under paragraph (d)(9) of this section and the defect meets the criteria for immediate repair in § 192.309(b). (B) The defect meets the criteria for immediate repair in § 192.933(d). (C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure. (D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.4 times the alternative maximum allowable operating pressure. (iii) If paragraph (d)(11)(ii) of this section does not require immediate repair, repair a defect within one year if any of the following apply: (A) The defect meets the criteria for repair within one year in § 192.933(d). (B) The alternative maximum allowable operating pressure was based on a design factor of 0.80 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure. (C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.50 times the alternative maximum allowable operating pressure. (D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.80 times the alternative maximum allowable operating pressure. (iv) Evaluate any defect not required to be repaired under paragraph (d)(11)(ii) or (iii) of this section to determine its growth rate, set the maximum interval for repair or re-inspection, and repair or re-inspect within that interval.

(e) *Is there any change in overpressure protection associated with operating at the alternative maximum allowable operating pressure?* Notwithstanding the required capacity of pressure relieving and limiting stations otherwise required by § 192.201, if an operator establishes a maximum allowable operating pressure for a pipeline segment in accordance with paragraph (a) of this section, an operator must:

(1) Provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the maximum allowable operating pressure; and

(2) Develop and follow a procedure for establishing and maintaining accurate set points for the supervisory control and data acquisition system.

[73 FR 62177, Oct. 17, 2008, as amended by Amdt. 192–111, 74 FR 62505, Nov. 30, 2009; Amdt. 192–120, 80 FR 12779, Mar. 11, 2015]

§ 192.621 Maximum allowable operating pressure: High-pressure distribution systems.

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part.

(2) 60 p.s.i. (414 kPa) gage, for a segment of a distribution system otherwise designed to operate at over 60 p.s.i. (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of § 192.197(c).

(3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

(4) The pressure limits to which a joint could be subjected without the possibility of its parting.

(5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37504, July 13, 1998]

§ 192.623 Maximum and minimum allowable operating pressure; Low-pressure distribution systems.

(a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person may operate a low pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

§ 192.625 Odorization of gas.

(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;

(i) An underground storage field;

(ii) A gas processing plant;

(iii) A gas dehydration plant; or

(iv) An industrial plant using gas in a process where the presence of an odorant:

(A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction;

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

(4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

(c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, materials, or pipe.

(2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

(d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by—

(1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

(2) Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.625, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.fdsys.gov*.

§ 192.627 Tapping pipelines under pressure.

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

§ 192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

§ 192.631 Control room management.

(a) *General.* (1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section, except that for each control room where an operator's activities are limited to either or both of:

(i) Distribution with less than 250,000 services, or

(ii) Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (d) (regarding fatigue), (i) (regarding compliance validation), and (j) (regarding compliance and deviations) of this section.

(2) The procedures required by this section must be integrated, as appropriate, with operating and emergency procedures required by §§ 192.605 and 192.615. An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraphs (b), (c)(5), (d)(2) and (d)(3), (f) and (g) of this section must be implemented no later than October 1, 2011. The procedures required by paragraphs (c)(1) through (4), (d)(1), (d)(4), and (e) must be implemented no later than August 1, 2012. The training procedures required by paragraph (h) must be implemented no later than August 1, 2012, except that any training required by another paragraph of this section must be implemented no later than the deadline for that paragraph.

(b) *Roles and responsibilities.* Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

(1) A controller's authority and responsibility to make decisions and take actions during normal operations;

(2) A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others;

(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers; and

(5) The roles, responsibilities and qualifications of others with the authority to direct or supersede the specific technical actions of a controller.

(c) *Provide adequate information.* Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference, see § 192.7) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

(3) Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months;

(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and

(5) Establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

(d) *Fatigue mitigation*. Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

(1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;

(2) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

(3) Train controllers and supervisors to recognize the effects of fatigue; and

(4) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

(e) *Alarm management*. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;

(3) Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed 15 months;

(4) Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan;

(5) Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

(6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.

(f) *Change management*. Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:

(1) Establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration;

(2) Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and

(3) Seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.

(g) *Operating experience*. Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:

(1) Review incidents that must be reported pursuant to 49 CFR part 191 to

determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to:

(i) Controller fatigue;

(ii) Field equipment;

(iii) The operation of any relief device;

(iv) Procedures;

(v) SCADA system configuration; and

(vi) SCADA system performance.

(2) Include lessons learned from the operator's experience in the training program required by this section.

(h) *Training.* Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

(2) Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;

(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures;

(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions;

(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application; and

(6) Control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018.

(i) *Compliance validation.* Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a State, to the appropriate State agency.

(j) *Compliance and deviations.* An operator must maintain for review during inspection:

(1) Records that demonstrate compliance with the requirements of this section; and

(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of a pipeline facility.

[Amdt. 192–112, 74 FR 63327, Dec. 3, 2009, as amended at 75 FR 5537, Feb. 3, 2010; 76 FR 35135, June 16, 2011; Amdt. 192–123, 82 FR 7997, Jan. 23, 2017]

Subpart M—Maintenance

§ 192.701 Scope.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

§ 192.703 General.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.

(b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

(c) Hazardous leaks must be repaired promptly.

§ 192.705 Transmission lines: Patrolling.

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

(b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

Class location of line	Maximum interval between patrols	
	At highway and railroad crossings	At all other places
1, 2	7½ months; but at least twice each calendar year.	15 months; but at least once each calendar year.
3	4½ months; but at least four times each calendar year.	7½ months; but at least twice each calendar year.
4	4½ months; but at least four times each calendar year.	4½ months; but at least four times each calendar year.

(c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

[Amdt. 192–21, 40 FR 20283, May 9, 1975, as amended by Amdt. 192–43, 47 FR 46851, Oct. 21, 1982; Amdt. 192–78, 61 FR 28786, June 6, 1996]

§ 192.706 Transmission lines: Leakage surveys.

Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with § 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted—

(a) In Class 3 locations, at intervals not exceeding 7½ months, but at least twice each calendar year; and

(b) In Class 4 locations, at intervals not exceeding 4½ months, but at least four times each calendar year.

[Amdt. 192–21, 40 FR 20283, May 9, 1975, as amended by Amdt. 192–43, 47 FR 46851, Oct. 21, 1982; Amdt. 192–71, 59 FR 6585, Feb. 11, 1994]

§ 192.707 Line markers for mains and transmission lines.

(a) *Buried pipelines*. Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:

(1) At each crossing of a public road and railroad; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

(b) *Exceptions for buried pipelines*. Line markers are not required for the following pipelines:

(1) Mains and transmission lines located offshore, or at crossings of or under waterways and other bodies of water.

(2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under § 192.614.

(3) Transmission lines in Class 3 or 4 locations until March 20, 1996.

(4) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.

(c) *Pipelines aboveground*. Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) *Marker warning*. The following must be written legibly on a background of sharply contrasting color on each line marker:

(1) The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with ¼ inch (6.4 millimeters) stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

[Amdt. 192–20, 40 FR 13505, Mar. 27, 1975; Amdt. 192–27, 41 FR 39752, Sept. 16, 1976, as amended by Amdt. 192–20A, 41 FR 56808, Dec. 30, 1976; Amdt. 192–44, 48 FR 25208, June 6, 1983; Amdt. 192–73, 60 FR 14650, Mar. 20, 1995; Amdt. 192–85, 63 FR 37504, July 13, 1998]

§ 192.709 Transmission lines: Record keeping.

Each operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.

(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

[Amdt. 192–78, 61 FR 28786, June 6, 1996]

§ 192.711 Transmission lines: General requirements for repair procedures.

(a) *Temporary repairs.* Each operator must take immediate temporary measures to protect the public whenever:

(1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and

(2) It is not feasible to make a permanent repair at the time of discovery.

(b) *Permanent repairs.* An operator must make permanent repairs on its pipeline system according to the following:

(1) Non integrity management repairs: The operator must make permanent repairs as soon as feasible.

(2) Integrity management repairs: When an operator discovers a condition on a pipeline covered under Subpart O–Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by § 192.933(d).

(c) *Welded patch.* Except as provided in § 192.717(b)(3), no operator may use a welded patch as a means of repair.

[Amdt. 192–114, 75 FR 48604, Aug. 11, 2010]

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) Operating pressure must be at a safe level during repair operations.

[Amdt. 192–88, 64 FR 69665, Dec. 14, 1999]

§ 192.715 Transmission lines: Permanent field repair of welds.

Each weld that is unacceptable under § 192.241(c) must be repaired as follows:

(a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of § 192.245.

(b) A weld may be repaired in accordance with § 192.245 while the segment of transmission line is in service if:

(1) The weld is not leaking;

(2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and

(3) Grinding of the defective area can be limited so that at least ⅛-inch (3.2 millimeters) thickness in the pipe weld remains.

(c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37504, July 13, 1998]

§ 192.717 Transmission lines: Permanent field repair of leaks.

Each permanent field repair of a leak on a transmission line must be made by—

(a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or

(b) Repairing the leak by one of the following methods:

(1) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS.

(2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.

(3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (267 Mpa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.

(4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically

apply a full encirclement split sleeve of appropriate design.

(5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

[Amdt. 192-88, 64 FR 69665, Dec. 14, 1999]

§ 192.719 Transmission lines: Testing of repairs.

(a) *Testing of replacement pipe.* If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

(b) *Testing of repairs made by welding.* Each repair made by welding in accordance with §§ 192.713, 192.715, and 192.717 must be examined in accordance with § 192.241.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-54, 51 FR 41635, Nov. 18, 1986]

§ 192.721 Distribution systems: Patrolling.

(a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

(1) In business districts, at intervals not exceeding 4½ months, but at least four times each calendar year; and

(2) Outside business districts, at intervals not exceeding 7½ months, but at least twice each calendar year.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-78, 61 FR 28786, June 6, 1996]

§ 192.723 Distribution systems: Leakage surveys.

(a) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section.

(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

(1) A leakage survey with leak detector equipment must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year.

(2) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months. However, for cathodically unprotected distribution lines subject to § 192.465(e) on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least once every 3 calendar years at intervals not exceeding 39 months.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-70, 58 FR 54528, 54529, Oct. 22, 1993; Amdt. 192-71, 59 FR 6585, Feb. 11, 1994; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 192-94, 69 FR 54592, Sept. 9, 2004]

§ 192.725 Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

§ 192.727 Abandonment or deactivation of facilities.

(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

(f) Each abandoned vault must be filled with a suitable compacted material.

(g) For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

(1) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at *http://www.npms.phmsa.dot.gov* or contact the NPMS National Repository at 703–317–3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; fax (202) 366–4566; e-mail *InformationResourcesManager@phmsa.dot.gov*. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

(2) [Reserved]

[Amdt. 192–8, 37 FR 20695, Oct. 3, 1972, as amended by Amdt. 192–27, 41 FR 34607, Aug. 16, 1976; Amdt. 192–71, 59 FR 6585, Feb. 11, 1994; Amdt. 192–89, 65 FR 54443, Sept. 8, 2000; 65 FR 57861, Sept. 26, 2000; 70 FR 11139, Mar. 8, 2005; Amdt. 192–103, 72 FR 4656, Feb. 1, 2007; 73 FR 16570, Mar. 28, 2008; 74 FR 2894, Jan. 16, 2009]

§ 192.731 Compressor stations: Inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§ 192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§ 192.735 Compressor stations: Storage of combustible materials.

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

(b) Aboveground oil or gasoline storage tanks must be protected in accordance with NFPA-30 (incorporated by reference, *see* § 192.7) .

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-119, 80 FR 181, Jan. 5, 2015; 80 FR 46847, Aug. 6, 2015]

§ 192.736 Compressor stations: Gas detection.

(a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is—

(1) Constructed so that at least 50 percent of its upright side area is permanently open; or

(2) Located in an unattended field compressor station of 1,000 horsepower (746 kW) or less.

(b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must—

(1) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and

(2) If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.

(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

[58 FR 48464, Sept. 16, 1993, as amended by Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.739 Pressure limiting and regulating stations: Inspection and testing.

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(b) For steel pipelines whose MAOP is determined under § 192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS.	MAOP plus 4 percent.
Unknown as a percentage of SMYS.	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-93, 68 FR 53901, Sept. 15, 2003; Amdt. 192-96, 69 FR 27863, May 17, 2004]

§ 192.740 Pressure regulating, limiting, and overpressure protection—Individual service lines directly connected to production, 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 production, gathering, or transmission pipeline that is not operated as part of a distribution system.

(b) Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every

3 calendar years, not exceeding 39 months, to determine that it is:

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Set to control or relieve at the correct pressure consistent with the pressure limits of § 192.197; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(c) This section does not apply to equipment installed on service lines that only serve engines that power irrigation pumps.

[Amdt. 192–123, 82 FR 7998, Jan. 23, 2017]

§ 192.741 Pressure limiting and regulating stations: Telemetering or recording gauges.

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district.

(b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(c) If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

§ 192.743 Pressure limiting and regulating stations: Capacity of relief devices.

(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in § 192.739(b), the capacity must be consistent with the pressure limits of § 192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

(b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

(c) If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.

[Amdt. 192–93, 68 FR 53901, Sept. 15, 2003, as amended by Amdt. 192–96, 69 FR 27863, May 17, 2004]

§ 192.745 Valve maintenance: Transmission lines.

(a) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

(b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

[Amdt. 192–43, 47 FR 46851, Oct. 21, 1982, as amended by Amdt. 192–93, 68 FR 53901, Sept. 15, 2003]

§ 192.747 Valve maintenance: Distribution systems.

(a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.

(b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

[Amdt. 192–43, 47 FR 46851, Oct. 21, 1982, as amended by Amdt. 192–93, 68 FR 53901, Sept. 15, 2003]

§ 192.749 Vault maintenance.

(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

(d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–43, 47 FR 46851, Oct. 21, 1982; Amdt. 192–85, 63 FR 37504, July 13, 1998]

§ 192.751 Prevention of accidental ignition.

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

(b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Post warning signs, where appropriate.

§ 192.753 Caulked bell and spigot joints.

(a) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psi (172kPa) gage must be sealed with:

(1) A mechanical leak clamp; or

(2) A material or device which:

(i) Does not reduce the flexibility of the joint;

(ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§ 192.53 (a) and (b) and 192.143.

(b) Each cast iron caulked bell and spigot joint that is subject to pressures of 25 psi (172kPa) gage or less and is exposed for any reason must be sealed by a means other than caulking.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–25, 41 FR 23680, June 11, 1976; Amdt. 192–85, 63 FR 37504, July 13, 1998; Amdt. 192–93, 68 FR 53901, Sept. 15, 2003]

§ 192.755 Protecting cast-iron pipelines.

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth movement;

(4) Apparent future excavations near the pipeline; or

(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of §§ 192.317(a), 192.319, and 192.361(b)–(d).

[Amdt. 192–23, 41 FR 13589, Mar. 31, 1976]

Subpart N—Qualification of Pipeline Personnel

SOURCE: Amdt. 192–86, 64 FR 46865, Aug. 27, 1999, unless otherwise noted.

§ 192.801 Scope.

(a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

(b) For the purpose of this subpart, a covered task is an activity, identified by the operator, that:

(1) Is performed on a pipeline facility;

(2) Is an operations or maintenance task;

(3) Is performed as a requirement of this part; and

(4) Affects the operation or integrity of the pipeline.

§ 192.803 Definitions.

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(a) Indicate a condition exceeding design limits; or

(b) Result in a hazard(s) to persons, property, or the environment.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

(a) Written examination;

(b) Oral examination;

(c) Work performance history review;

(d) Observation during:

(1) Performance on the job,

(2) On the job training, or

(3) Simulations;

(e) Other forms of assessment.

Qualified means that an individual has been evaluated and can:

(a) Perform assigned covered tasks; and

(b) Recognize and react to abnormal operating conditions.

[Amdt. 192–86, 64 FR 46865, Aug. 27, 1999, as amended by Amdt. 192–90, 66 FR 43523, Aug. 20, 2001]

§ 192.805 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(a) Identify covered tasks;

(b) Ensure through evaluation that individuals performing covered tasks are qualified;

(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;

(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;

(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

(f) Communicate changes that affect covered tasks to individuals performing those covered tasks;

(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed;

(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the administrator or state agency has verified that it complies with this section. Notifications to PHMSA may be submitted by electronic mail to *InformationResourcesManager@dot.gov*, or by mail to ATTN: Information Resources Manager DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, New Jersey Avenue SE., Washington, DC 20590.

[Amdt. 192–86, 64 FR 46865, Aug. 27, 1999, as amended by Amdt. 192–100, 70 FR 10335, Mar. 3, 2005; Amdt. 192–120, 80 FR 12779, Mar. 11, 2015]

§ 192.807 Recordkeeping.

Each operator shall maintain records that demonstrate compliance with this subpart.

(a) Qualification records shall include:

(1) Identification of qualified individual(s);

(2) Identification of the covered tasks the individual is qualified to perform;

(3) Date(s) of current qualification; and

(4) Qualification method(s).

(b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

§ 192.809 General.

(a) Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.

(b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

(c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999.

(d) After October 28, 2002, work performance history may not be used as a sole evaluation method.

(e) After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

[Amdt. 192–86, 64 FR 46865, Aug. 27, 1999, as amended by Amdt. 192–90, 66 FR 43524, Aug. 20, 2001; Amdt. 192–100, 70 FR 10335, Mar. 3, 2005]

Subpart O—Gas Transmission Pipeline Integrity Management

SOURCE: 68 FR 69817, Dec. 15, 2003, unless otherwise noted.

§ 192.901 What do the regulations in this subpart cover?

This subpart prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this part. For gas transmission pipelines constructed of plastic, only the requirements in §§ 192.917, 192.921, 192.935 and 192.937 apply.

§ 192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment.

Confirmatory direct assessment is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in § 192.3.

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.*, external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under § 192.5; or

(ii) A Class 4 location under § 192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See figure E.I.A. in appendix E.)

(4) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy with a distance of 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (*i.e.*, the prorated number of buildings intended for human occupancy is equal to 20 × (660 feet) [or 200 meters]/potential impact radius in feet [or meters]^2).

Identified site means each of the following areas:

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d^2)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

NOTE: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7) to calculate the impact radius formula.

Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004; Amdt. 192–95, 69 FR 29904, May 26, 2004; Amdt. 192–103, 72 FR 4657, Feb. 1, 2007; Amdt. 192–119, 80 FR 181, Jan. 5, 2015]

§ 192.905 How does an operator identify a high consequence area?

(a) *General.* To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in § 192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (*See* appendix E.I. for guidance on identifying high consequence areas.)

(b)(1) *Identified sites.* An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

(2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.

(i) Visible marking (e.g., a sign); or

(ii) The site is licensed or registered by a Federal, State, or local government agency; or

(iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

(c) *Newly identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

§ 192.907 What must an operator do to implement this subpart?

(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

(b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.

§ 192.909 How can an operator change its integrity management program?

(a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.

(b) *Notification.* An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 6, 2004]

§ 192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (*see* §192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, *see*

§ 192.7) for more detailed information on the listed element.)

(a) An identification of all high consequence areas, in accordance with § 192.905.

(b) A baseline assessment plan meeting the requirements of § 192.919 and § 192.921.

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.

(d) A direct assessment plan, if applicable, meeting the requirements of § 192.923, and depending on the threat assessed, of §§ 192.925, 192.927, or 192.929.

(e) Provisions meeting the requirements of § 192.933 for remediating conditions found during an integrity assessment.

(f) A process for continual evaluation and assessment meeting the requirements of § 192.937.

(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of § 192.931.

(h) Provisions meeting the requirements of § 192.935 for adding preventive and mitigative measures to protect the high consequence area.

(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of § 192.945.

(j) Record keeping provisions meeting the requirements of § 192.947.

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

(p) A process for identification and assessment of newly-identified high consequence areas. (*See* § 192.905 and § 192.921.)

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.913 When may an operator deviate its program from certain requirements of this subpart?

(a) *General.* ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.

(b) *Exceptional performance.* An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions.

(1) To deviate from any of the requirements set forth in paragraph (c) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements—

(i) A comprehensive process for risk analysis;

(ii) All risk factor data used to support the program;

(iii) A comprehensive data integration process;

(iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;

(v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

(vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;

(vii) Semi-annual performance measures beyond those required in § 192.945 that are part of the operator's performance plan. (*See* § 192.911(i).) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with § 192.951; and

(viii) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

(2) In addition to the requirements for the performance-based plan, an operator must—

(i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.

(ii) Remediate all anomalies identified in the more recent assessment according to the requirements in § 192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

(c) *Deviation.* Once an operator has demonstrated that it has satisfied the requirements of paragraph (b) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this subpart only in the following instances.

(1) The time frame for reassessment as provided in § 192.939 except that reassessment by some method allowed under this subpart (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(2) The time frame for remediation as provided in § 192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.915 What knowledge and training must personnel have to carry out an integrity management program?

(a) *Supervisory personnel.* The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(b) *Persons who carry out assessments and evaluate assessment results.* The integrity management program must provide criteria for the qualification of any person—

(1) Who conducts an integrity assessment allowed under this subpart; or

(2) Who reviews and analyzes the results from an integrity assessment and evaluation; or

(3) Who makes decisions on actions to be taken based on these assessments.

(c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person—

(1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or

(2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in

ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§ 192.935) for the covered segment.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with § 192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under § 192.921, or a reassessment under § 192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment.

(3) *Manufacturing and construction defects.* If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the

maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in § 192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 6, 2004]

§ 192.919 What must be in the baseline assessment plan?

An operator must include each of the following elements in its written baseline assessment plan:

(a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (*See* § 192.917.);

(b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (*See* § 192.917.) More than one method may be required to address all the threats to the covered pipeline segment;

(c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule;

(d) If applicable, a direct assessment plan that meets the requirements of §§ 192.923, and depending on the threat to be addressed, of § 192.925, § 192.927, or § 192.929; and

(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with § 192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with, as applicable, the requirements specified in §§ 192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with § 192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in § 192.917.

(c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in § 192.917(e) to address particular threats that it has identified.

(d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with § 192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in § 192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of § 192.937 and § 192.939.

(f) *Newly identified areas.* When an operator identifies a new high consequence area (*see* § 192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

(h) *Plastic transmission pipeline.* If the threat analysis required in § 192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of § 192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18232, Apr. 6, 2004]

§ 192.923 How is direct assessment used and for what threats?

(a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC).

(b) *Primary method*. An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—

(1) Section 192.925 and ASME/ANSI B31.8S (incorporated by reference, see § 192.7) section 6.4, and NACE SP0502 (incorporated by reference, *see* § 192.7) , if addressing external corrosion (EC).

(2) Section 192.927 and ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 6.4, appendix B2, if addressing internal corrosion (IC).

(3) Section 192.929 and ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), appendix A3, if addressing stress corrosion cracking (SCC).

(c) *Supplemental method*. An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in § 192.931.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–114, 75 FR 48604, Aug. 11, 2010; Amdt. 192–119, 80 FR 178, 182, Jan. 5, 2015; 80 FR 46847, Aug. 6, 2015]

§ 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(a) *Definition*. ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

(b) *General requirements*. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 6.4, and in NACE SP0502 (incorporated by reference, *see* § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect inspection, direct examination, and post assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§ 192.917(b)) to evaluate the covered segment for the threat of third party damage and to address the threat as required by § 192.917(e)(1).

(1) *Preassessment*. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 3, the plan's procedures for preassessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE SP0502, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) *Indirect inspection*. In addition to the requirements in ASME/ANSI B31.8S, section 6.4 and in NACE SP0502, section 4, the plan's procedures for indirect inspection of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(3) *Direct examination*. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 5, the plan's procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting

ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE SP0502), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502);

(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE SP0502.

(4) *Post assessment and continuing evaluation.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939. (See Appendix D of NACE SP0502.)

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 29904, May 26, 2004; Amdt. 192–114, 75 FR 48604, Aug. 11, 2010; Amdt. 192–119, 80 FR 178, Jan. 5, 2015; Amdt. 192–120, 80 FR 12779, Mar. 11, 2015]

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 6.4 and appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with § 192.921 (a)(4) or § 192.937(c)(4).

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.

(1) *Preassessment.* In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—

(i) All data elements listed in appendix A2 of ASME/ANSI B31.8S;

(ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (*See* paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps;

the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;

(iii) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and

(iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

(2) *ICDA region identification.* An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology," (incorporated by reference, *see* § 192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.

(3) *Identification of locations for excavation and direct examination.* An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (e.g., sags, drips, valves, manifolds, deadlegs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933;

(ii) As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and

(iii) Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with § 192.933.

(4) *Post-assessment evaluation and monitoring.* An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. An operator must carry out this evaluation within a year of conducting an ICDA; and

(ii) Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with § 192.933.

(A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

(5) *Other requirements.* The ICDA plan must also include—

(i) Criteria an operator will apply in making key decisions (e.g., ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and

(iii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of § 192.933 may be limited to covered segments.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18232, Apr. 6, 2004]

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

(a) *Definition.* Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, appendix A3.

(2) *Assessment method.* The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004]

§ 192.931 How may Confirmatory Direct Assessment (CDA) be used?

An operator using the confirmatory direct assessment (CDA) method as allowed in § 192.937 must have a plan that meets the requirements of this section and of §§ 192.925 (ECDA) and § 192.927 (ICDA).

(a) *Threats.* An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.

(b) *External corrosion plan.* An operator's CDA plan for identifying external corrosion must comply with § 192.925 with the following exceptions.

(1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.

(2) The procedures for direct examination and remediation must provide that—

(i) All immediate action indications must be excavated for each ECDA region; and

(ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.

(c) *Internal corrosion plan.* An operator's CDA plan for identifying internal corrosion must comply with § 192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

(d) *Defects requiring near-term remediation.* If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE SP0502 (incorporated by reference, *see* § 192.7), section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with § 192.933 until the operator has completed reassessment using one of the assessment techniques allowed in § 192.937.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–114, 75 FR 48604, Aug. 11, 2010; Amdt. 192–119, 80 FR 178, Jan. 5, 2015]

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* § 192.7); Pipeline Research Council, International, PR–3–805 (R–STRENG) (incorporated by reference, *see* § 192.7); or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with § 192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must notify PHMSA under § 192.949 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 7, Figure

4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation*—(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, *see* § 192.7) , PRCI PR–3–805 (R–STRENG) (incorporated by reference, *see* § 192.7), or an alternative equivalent method of remaining strength calculation.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004; Amdt. 192–104, 72 FR 39016, July 17, 2007; Amdt. 192–119, 80 FR 182, Jan. 5, 2015; 80 FR 46847, Aug. 6, 2015]

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* § 192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(b) Third party damage and outside force damage—

(1) *Third party damage.* An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(i) Using qualified personnel (*see* §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, *see* §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) *Outside force damage.* If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(d) *Pipelines operating below 30% SMYS.* An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

(1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

(3) Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).

(e) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004; Amdt. 192–95, 69 FR 29904, May 26, 2004; Amdt. 192–114, 75 FR 48604, Aug. 11, 2010; Amdt. 192–119, 80 FR 178, Jan. 5, 2015]

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in § 192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under § 192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in § 192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* § 192.917), or by confirmatory direct assessment under the conditions specified in § 192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with § 192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with as applicable, the requirements specified in §§ 192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with § 192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(5) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with § 192.931.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.939 What are the required reassessment intervals?

An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

(1) *Pressure test or internal inspection or other equivalent technology.* An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

(i) Basing the interval on the identified threats for the covered segment (see § 192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by § 192.917; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, *see* § 192.7), section 5, Table 3.

(2) *External Corrosion Direct Assessment.* An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, *see* § 192.7).

(3) *Internal Corrosion or SCC Direct Assessment.* An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

(i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;

(ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and

(iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.

(b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following—

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low stress reassessment in accordance with § 192.941.

(2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

(3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.

(4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with § 192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(5) Reassessment by the low stress assessment method at 7-year intervals in accordance with § 192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(6) The following table sets forth the maximum reassessment intervals. Also

refer to Appendix E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

MAXIMUM REASSESSMENT INTERVAL

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment.	10 years (*)	15 years (*)	20 years. (**)
Confirmatory Direct Assessment.	7 years	7 years	7 years.
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in § 192.941.

(*) A Confirmatory direct assessment as described in § 192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004; Amdt. 192–114, 75 FR 48604, Aug. 11, 2010; Amdt. 192–119, 80 FR 178, 182, Jan. 5, 2015]

§ 192.941 What is a low stress reassessment?

(a) *General.* An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with § 192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§ 192.919 and 192.921.

(b) *External corrosion.* An operator must take one of the following actions to address external corrosion on the low stress covered segment.

(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (*i.e.* indirect examination tool/method) at least every 7 years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where electrical surveys are impractical.* If an electrical survey is impractical on the covered segment an operator must—

(i) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and

(ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(c) *Internal corrosion.* To address the threat of internal corrosion on a covered segment, an operator must—

(1) Conduct a gas analysis for corrosive agents at least once each calendar year;

(2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and

(3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1)–(c)(2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.943 When can an operator deviate from these reassessment intervals?

(a) *Waiver from reassessment interval in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval required by § 192.939 if OPS finds a waiver would not be inconsistent with pipeline safety.

(1) *Lack of internal inspection tools.* An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

(2) *Maintain product supply.* An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.

(b) *How to apply.* If one of the conditions specified in paragraph (a) (1) or (a) (2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18234, Apr. 6, 2004]

§ 192.945 What methods must an operator use to measure program effectiveness?

(a) *General.* An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7 of this part), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by § 191.17 of this subchapter.

(b) *External Corrosion Direct assessment.* In addition to the general requirements for performance measures in paragraph (a) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of § 192.925.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18234, Apr. 6, 2004; 75 FR 72906, Nov. 26, 2010]

§ 192.947 What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.

(a) A written integrity management program in accordance with § 192.907;

(b) Documents supporting the threat identification and risk assessment in accordance with § 192.917;

(c) A written baseline assessment plan in accordance with § 192.919;

(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;

(e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with § 192.915;

(f) Schedule required by § 192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.

(g) Documents to carry out the requirements in §§ 192.923 through 192.929 for a direct assessment plan;

(h) Documents to carry out the requirements in § 192.931 for confirmatory direct assessment;

(i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.949 How does an operator notify PHMSA?

An operator must provide any notification required by this subpart by—

(a) Sending the notification by electronic mail to *InformationResourcesManager@dot.gov;* or

(b) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, 1200 New Jersey Ave. SE., Washington, DC 20590.

[Amdt. 192–120, 80 FR 12779, Mar. 11, 2015]

§ 192.951 Where does an operator file a report?

An operator must file any report required by this subpart electronically to the Pipeline and Hazardous Materials Safety Administration in accordance with § 191.7 of this subchapter.

[Amdt. 192–115, 75 FR 72906, Nov. 26, 2010]

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

SOURCE: 74 FR 63934, Dec. 4, 2009, unless otherwise noted.

§ 192.1001 What definitions apply to this subpart?

The following definitions apply to this subpart:

Excavation Damage means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

Hazardous Leak means a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

Integrity Management Plan or *IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart.

Integrity Management Program or *IM Program* means an overall approach by an operator to ensure the integrity of its gas distribution system.

Mechanical fitting means a mechanical device used to connect sections of pipe. The term "Mechanical fitting" applies only to:

(1) Stab Type fittings;

(2) Nut Follower Type fittings;

(3) Bolted Type fittings; or

(4) Other Compression Type fittings.

Small LPG Operator means an operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

[74 FR 63934, Dec. 4, 2009, as amended at 76 FR 5499, Feb. 1, 2011]

§ 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, other than a master meter operator or a small LPG operator, must follow the requirements in §§ 192.1005 through 192.1013 of this subpart. A master meter operator or small LPG operator of a gas distribution pipeline must follow the requirements in § 192.1015 of this subpart.

(b) *Exceptions.* This subpart does not apply to an individual service line directly connected to a transmission, gathering, or production pipeline.

[Amdt. 192–123, 82 FR 7998, Jan. 23, 2017]

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

No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in § 192.1007.

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

A written integrity management plan must contain procedures for developing and implementing the following elements:

(a) *Knowledge.* An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(1) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

(2) Consider the information gained from past design, operations, and maintenance.

(3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

(4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

(5) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

(b) *Identify threats.* The operator must consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other concerns 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, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

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

(d) *Identify and implement measures to address risks.* Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).

(e) *Measure performance, monitor results, and evaluate effectiveness.* (1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(i) Number of hazardous leaks either eliminated or repaired as required by § 192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(iv) Total number of leaks either eliminated or repaired, categorized by cause;

(v) Number of hazardous leaks either eliminated or repaired as required by § 192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material; and

(vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

(f) *Periodic Evaluation and Improvement.* An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(g) *Report results.* Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by § 191.11. An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

[74 FR 63934, Dec. 4, 2009, as amended at 76 FR 5499, Feb. 1, 2011]

§ 192.1009 What must an operator report when a mechanical fitting fails?

(a) Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit a report on each mechanical fitting failure, excluding any failure that results only in a nonhazardous leak, on a Department of Transportation Form PHMSA F-7100.1-2. The report(s) must be submitted in accordance with § 191.12.

(b) The mechanical fitting failure reporting requirements in paragraph (a) of this section do not apply to the following:

(1) Master meter operators;

(2) Small LPG operator as defined in § 192.1001; or

(3) LNG facilities.

[76 FR 5499, Feb. 1, 2011]

§ 192.1011 What records must an operator keep?

An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.

§ 192.1013 When may an operator deviate from required periodic inspections under this part?

(a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart.

(b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency. The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

(c) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

§ 192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?

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

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

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

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

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

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

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

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

(c) *Records*. The operator must maintain, for a period of at least 10 years, the following records:

(1) A written IM plan in accordance with this section, including superseded IM plans;

(2) Documents supporting threat identification; and

(3) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

Appendix A to Part 192 [Reserved]

Appendix B to Part 192—Qualification of Pipe

I. Listed Pipe Specifications

ANSI/API Specification 5L—Steel pipe, "Specification for Line Pipe" (incorporated by reference, *see* §192.7).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference, *see* §192.7).

ASTM A106/A106M—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference, *see* §192.7).

ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference, *see* §192.7).

ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference, *see* §192.7).

ASTM A671/A671M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference, *see* §192.7).

ASTM A672/672M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference, *see* §192.7).

ASTM A691/A691M—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures" (incorporated by reference, *see* §192.7).

ASTM D2513-99, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings," (incorporated by reference, *see* §192.7).

ASTM D2513-09a—Polyethylene thermoplastic pipe and tubing, "Standard Specification for Polyethylene (PE) gas Pressure Pipe, Tubing, and Fittings", (incorporated by reference, *see* §192.7).

ASTM D2517—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, *see* §192.7).

II. *Steel pipe of unknown or unlisted specification.*

A. *Bending Properties.* For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53/A53M (incorporated by reference, *see* §192.7), except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. *Weldability.* A girth weld must be made in the pipe by a welder who is qualified under subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference, *see* §192.7). If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code (ibr, *see* 192.7). The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L (incorporated by reference, *see* §192.7). All test specimens shall be selected at random and the following number of tests must be performed:

NUMBER OF TENSILE TESTS—ALL SIZES

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in §192.55(c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting appendix B to part 192, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.fdsys.gov.*

Appendix C to Part 192—Qualification of Welders for Low Stress Level Pipe

I. *Basic test.* The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than ⅛-inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered. A welder who successfully passes a butt-weld qualification test under this section shall be qualified to weld on all pipe diameters less than or equal to 12 inches.

II. *Additional tests for welders of service line connections to mains.* A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. *Periodic tests for welders of small service lines.* Two samples of the welder's work, each about 8 inches (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in subparagraph (1) of this paragraph.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37504, July 13, 1998; Amdt. 192–94, 69 FR 32896, June 14, 2004]

Appendix D to Part 192—Criteria for Cathodic Protection and Determination of Measurements

I. *Criteria for cathodic protection*— A. *Steel, cast iron, and ductile iron structures.* (1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.

(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. *Aluminum structures.* (1) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II and IV of this appendix.

(2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(3) Notwithstanding the alternative minimum criteria in paragraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful

investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures.* A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of section I of this appendix.

III. *Determination of polarization voltage shift.* The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of section I of this appendix.

IV. *Reference half cells.* A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated cooper-copper sulfate half cell. Two commonly used reference half cells are listed below along with their voltage equivalent to −0.85 volt as referred to a saturated copper-copper sulfate half cell:

(1) Saturated KCl calomel half cell: −0.78 volt.

(2) Silver-silver chloride half cell used in sea water: −0.80 volt.

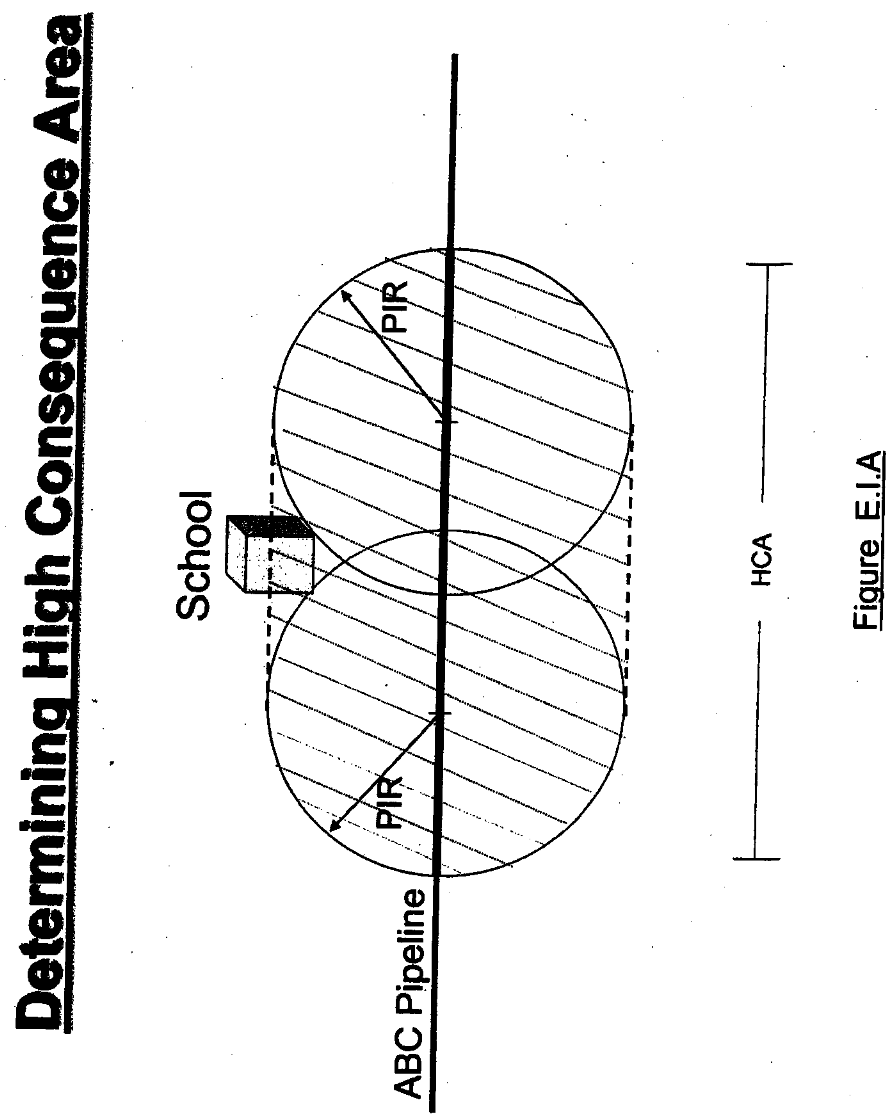
C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

[Amdt. 192–4, 36 FR 12305, June 30, 1971]

Appendix E to Part 192—Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

I. Guidance on Determining a High Consequence Area

To determine which segments of an operator's transmission pipeline system are covered for purposes of the integrity management program requirements, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. (Refer to figure E.I.A for a diagram of a high consequence area).



II. Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines

(a) Table E.II.1 gives guidance to help an operator implement requirements on additional preventive and mitigative measures for addressing time dependent and independent threats for a transmission pipeline operating below 30% SMYS not in an HCA (*i.e.* outside of potential impact circle) but located within a Class 3 or Class 4 Location.

(b) Table E.II.2 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats for a transmission pipeline in an HCA.

(c) Table E.II.3 gives guidance on preventative & mitigative measures addressing time dependent and independent threats for transmission pipelines that operate below 30% SMYS, in HCAs.

Table E.II.1: Preventive and Mitigative Measures for Transmission Pipelines Operating Below 30% SMYS not in an HCA but in a Class 3 or Class 4 Location

(Column 1) Threat	Existing 192 Requirements (Column 2) Primary	(Column 3) Secondary	(Column 4) Additional (to 192 requirements) Preventive and Mitigative Measures
External Corrosion	455-(Gen. Post 1971), 457-(Gen. Pre-1971) 459-(Examination), 461-(Ext. coating) 463-(CP), 465-(Monitoring) 467-(Elect isolation), 469-Test stations) 471-(Test leads), 473-(Interference) 479-(Atmospheric), 481-(Atmospheric) 485-(Remedial), 705-(Patrol) 706-(Leak survey), 711 (Repair – gen.) 717-(Repair – perm.)	603-(Gen Oper'n) 613-(Surveillance)	For Cathodically Protected Transmission Pipeline: • Perform semi-annual leak surveys. For Unprotected Transmission Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impractical: • Perform quarterly leak surveys
Internal Corrosion	475-(Gen IC), 477-(IC monitoring) 485-(Remedial), 705-(Patrol) 706-(Leak survey), 711 (Repair – gen.) 717-(Repair – perm.)	53(a)-(Materials) 603-(Gen Oper'n) 613-(Surveillance)	• Perform semi-annual leak surveys.

3rd Party Damage	103-(Gen. Design), 111-(Design factor) 317-(Hazard prot), 327-(Cover) 614-(Dam. Prevent), 616-(Public education) 705-(Patrol), 707-(Line markers) 711 (Repair – gen.), 717-(Repair – perm.)	615-(Emerg. Plan)	• Participation in state one-call system. • Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND • Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

Table E.II.2 Assessment Requirements for Transmission Pipelines in HCAs (Re-assessment intervals are maximum allowed)

	Re-Assessment Requirements (see Note 3)					
	At or above 50% SMYS		At or above 30% SMYS up to 50% SMYS		Below 30% SMYS	
Baseline Assessment Method (see Note 3)	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method
Pressure Testing	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	Pressure Test or ILI or DA				
		Repeat inspection cycle every 10 years	15(see Note 1)	Pressure Test or ILI or DA (see Note 1)		
				Repeat inspection cycle every 15 years	20	Pressure Test or ILI or DA
						Repeat inspection cycle every 20 years
In-Line Inspection	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	ILI or DA or Pressure Test				
		Repeat inspection cycle every 10 years	15(see Note 1)	ILI or DA or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	ILI or DA or Pressure Test

						Repeat inspection cycle every 20 years
Direct Assessment	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	DA or ILI or Pressure Test				
		Repeat inspection cycle every 10 years	15(see Note 1)	DA or ILI or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	DA or ILI or Pressure Test
						Repeat inspection cycle every 20 years

Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S

Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of P&M

Note 3: Operator may utilize "other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe"

Table E.II.3

Preventative & Mitigative Measures addressing Time Dependent and Independent Threats for Transmission Pipelines that Operate Below 30% SMYS , in HCAs

Threat	Existing 192 Requirements		Additional (to 192 requirements) Preventive & Mitigative Measures
	Primary	Secondary	
External Corrosion	455-(Gen. Post 1971) 457-(Gen. Pre-1971) 459-(Examination) 461-(Ext. coating) 463-(CP) 465-(Monitoring) 467-(Elect isolation)	603-(Gen Oper) 613-(Surveil)	<u>For Cathodically Protected Trnm. Pipelines</u> • Perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years. Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment. Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

External Corrosion	469-Test stations) 471-(Test leads) 473-(Interference) 479-(Atmospheric) 481-(Atmospheric) 485-(Remedial) 705-(Patrol) 706-(Leak survey) 711 (Repair – gen.) 717-(Repair – perm.)		<u>For Unprotected Trmn. Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impracticable</u> • Conduct quarterly leak surveys AND • Every 1-1/2 years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
Internal Corrosion	475-(Gen IC) 477-(IC monitoring) 485-(Remedial) 705-(Patrol) 706-(Leak survey) 711 (Repair – gen.) 717-(Repair – perm.)	53(a)-(Materials) 603-(Gen Oper) 613-(Surveil)	• Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCAs, • Periodic testing of fluid removed from pipelines. Specifically, once each calendar year from each storage field that may affect transmission pipelines in HCAs, AND • At least every 7 years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records.

3rd Party Damage	103-(Gen. Design) 111-(Design factor) 317-(Hazard prot) 327-(Cover) 614-(Dam. Prevent) 616-(Public educat) 705-(Patrol) 707-(Line markers) 711 (Repair – gen.) 717-(Repair – perm.)	615 –(Emerg Plan)	• Participation in state one-call system, • Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND • Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

[Amdt. 192-95, 69 FR 18234, Apr. 6, 2004, as amended by Amdt. 192-95, May 26, 2004]

PART 193—LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS

(4) Does the enforcement authority (if one exists) have a reliable mechanism (e.g., mandatory reporting, complaint-driven reporting) for learning about excavation damage to underground facilities?

(5) Does the State employ excavation damage investigation practices that are adequate to determine the responsible party or parties when excavation damage to underground facilities occurs?

(6) At a minimum, do the State's excavation damage prevention requirements include the following:

(i) Excavators may not engage in excavation activity without first using an available one-call notification system to establish the location of underground facilities in the excavation area.

(ii) Excavators may not engage in excavation activity in disregard of the marked location of a pipeline facility as established by a pipeline operator.

(iii) An excavator who causes damage to a pipeline facility:

(A) Must report the damage to the operator of the facility at the earliest practical moment following discovery of the damage; and

(B) If the damage results in the escape of any PHMSA regulated natural and other gas or hazardous liquid, must promptly report to other appropriate authorities by calling the 911 emergency telephone number or another emergency telephone number.

(7) Does the State limit exemptions for excavators from its excavation damage prevention law? A State must provide to PHMSA a written justification for any exemptions for excavators from State damage prevention requirements. PHMSA will make the written justifications available to the public.

(b) PHMSA may consider individual enforcement actions taken by a State in evaluating the effectiveness of a State's damage prevention enforcement program.

§ 198.57 What is the process PHMSA will use to notify a State that its damage prevention enforcement program appears to be inadequate?

PHMSA will issue a notice of inadequacy to the State in accordance with 49 CFR 190.5. The notice will state the basis for PHMSA's determination that the State's damage prevention enforcement program appears inadequate for purposes of this subpart and set forth the State's response options.

§ 198.59 How may a State respond to a notice of inadequacy?

A State receiving a notice of inadequacy will have 30 days from receipt of the notice to submit a written response to the PHMSA official who issued the notice. In its response, the State may include information and explanations concerning the alleged inadequacy or contest the allegation of inadequacy and request the notice be withdrawn.

§ 198.61 How is a State notified of PHMSA's final decision?

PHMSA will issue a final decision on whether the State's damage prevention enforcement program has been found inadequate in accordance with 49 CFR 190.5.

§ 198.63 How may a State with an inadequate damage prevention enforcement program seek reconsideration by PHMSA?

At any time following a finding of inadequacy, the State may petition PHMSA to reconsider such finding based on changed circumstances including improvements in the State's enforcement program. Upon receiving a petition, PHMSA will reconsider its finding of inadequacy promptly and will notify the State of its decision on reconsideration promptly but no later than the time of the next annual certification review.

PART 199—DRUG AND ALCOHOL TESTING

Subpart A—General

Subpart B—Drug Testing

Subpart C—Alcohol Misuse Prevention Program

AUTHORITY: 49 U.S.C. 5103, 60102, 60104, 60108, 60117, and 60118; 49 CFR 1.53.

SOURCE: 53 FR 47096, Nov. 21, 1988, unless otherwise noted.

Subpart A—General

§ 199.1 Scope.

This part requires operators of pipeline facilities subject to part 192, 193, or 195 of this chapter to test covered employees for the presence of prohibited drugs and alcohol.

[Amdt. 199–19, 66 FR 47117, Sept. 11, 2001]

§ 199.2 Applicability.

(a) This part applies to pipeline operators only with respect to employees located within the territory of the United States, including those employees located within the limits of the "Outer Continental Shelf " as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to any person for whom compliance with this part would violate the domestic laws or policies of another country.

(c) This part does not apply to covered functions performed on—

(1) Master meter systems, as defined in § 191.3 of this chapter; or

(2) Pipeline systems that transport only petroleum gas or petroleum gas/air mixtures.

[Amdt. 199–19, 66 FR 47117, Sept. 11, 2001]

§ 199.3 Definitions.

As used in this part—

Accident means an incident reportable under part 191 of this chapter involving gas pipeline facilities or LNG facilities, or an accident reportable under part 195 of this chapter involving hazardous liquid pipeline facilities.

Administrator means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

Covered employee, employee, or individual to be tested means a person who performs a covered function, including persons employed by operators, contractors engaged by operators, and persons employed by such contractors.

Covered function means an operations, maintenance, or emergency-response function regulated by part 192, 193, or 195 of this chapter that is performed on a pipeline or on an LNG facility.

DOT Procedures means the Procedures for Transportation Workplace Drug and Alcohol Testing Programs published by the Office of the Secretary of Transportation in part 40 of this title.

Fail a drug test means that the confirmation test result shows positive evidence of the presence under DOT Procedures of a prohibited drug in an employee's system.

Operator means a person who owns or operates pipeline facilities subject to part 192, 193, or 195 of this chapter.

Pass a drug test means that initial testing or confirmation testing under DOT Procedures does not show evidence of the presence of a prohibited drug in a person's system.

Performs a covered function includes actually performing, ready to perform, or immediately available to perform a covered function.

Positive rate for random drug testing means the number of verified positive results for random drug tests conducted under this part plus the number of refusals of random drug tests required by this part, divided by the total number of random drug tests results (*i.e.*, positives, negatives, and refusals) under this part.

Prohibited drug means any of the following substances specified in Schedule I or Schedule II of the Controlled Substances Act (21 U.S.C. 812): marijuana, cocaine, opiates, amphetamines, and phencyclidine (PCP).

Refuse to submit, refuse, or refuse to take means behavior consistent with DOT Procedures concerning refusal to take a drug test or refusal to take an alcohol test.

State agency means an agency of any of the several states, the District of Columbia, or Puerto Rico that participates under the pipeline safety laws (49 U.S.C. 60101 *et seq.*)

[53 FR 47096, Nov. 21, 1988, as amended by Amdt. 199–2, 54 FR 51850, Dec. 18, 1989; 59 FR 62227, Dec. 2, 1994; Amdt. 199–13, 61 FR 18518, Apr. 26, 1996; Amdt. 199–15, 63 FR 13000, Mar. 17, 1998; Amdt. 199–19, 66 FR 47117, Sept. 11, 2001; 68 FR 11750, Mar. 12, 2003; 68 FR 75465, Dec. 31, 2003; 70 FR 11140, Mar. 8, 2005]

§ 199.5 DOT procedures.

The anti-drug and alcohol programs required by this part must be conducted according to the requirements of this part and DOT Procedures. Terms and concepts used in this part have the same meaning as in DOT Procedures. Violations of DOT Procedures with respect to anti-drug and alcohol programs required by this part are violations of this part.

[Amdt. 199–19, 66 FR 47118, Sept. 11, 2001]

§ 199.7 Stand-down waivers.

(a) Each operator who seeks a waiver under § 40.21 of this title from the stand-down restriction must submit an application for waiver in duplicate to the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, 1200 New Jersey Avenue, SE, Washington, DC 20590–0001.

(b) Each application must—

(1) Identify § 40.21 of this title as the rule from which the waiver is sought;

(2) Explain why the waiver is requested and describe the employees to be covered by the waiver;

(3) Contain the information required by § 40.21 of this title and any other information or arguments available to support the waiver requested; and

(4) Unless good cause is shown in the application, be submitted at least 60 days before the proposed effective date of the waiver.

(c) No public hearing or other proceeding is held directly on an application before its disposition under this section. If the Associate Administrator determines that the application contains adequate justification, he or she grants the waiver. If the Associate Administrator determines that the application does not justify granting the waiver, he or she denies the application. The Associate Administrator notifies each applicant of the decision to grant or deny an application.

[Amdt. 199–19, 66 FR 47118, Sept. 11, 2001, as amended at 70 FR 11140, Mar. 8, 2005; 74 FR 2894, Jan. 16, 2009]

§ 199.9 Preemption of State and local laws.

(a) Except as provided in paragraph (b) of this section, this part preempts any State or local law, rule, regulation, or order to the extent that:

(1) Compliance with both the State or local requirement and this part is not possible;

(2) Compliance with the State or local requirement is an obstacle to the accomplishment and execution of any requirement in this part; or

(3) The State or local requirement is a pipeline safety standard applicable to interstate pipeline facilities.

(b) This part shall not be construed to preempt provisions of State criminal law that impose sanctions for reckless conduct leading to actual loss of life, injury, or damage to property, whether the provisions apply specifically to transportation employees or employers or to the general public.

[Amdt. 199–9, 59 FR 7430, Feb. 15, 1994. Redesignated and amended by Amdt. 199–19, 66 FR 47119, Sept. 11, 2001]

Subpart B—Drug Testing

§ 199.100 Purpose.

The purpose of this subpart is to establish programs designed to help prevent accidents and injuries resulting from the use of prohibited drugs by employees who perform covered functions for operators of certain pipeline facilities subject to part 192, 193, or 195 of this chapter.

[Amdt. 199-19, 66 FR 47118, Sept. 11, 2001]

§ 199.101 Anti-drug plan.

(a) Each operator shall maintain and follow a written anti-drug plan that conforms to the requirements of this part and the DOT Procedures. The plan must contain—

(1) Methods and procedures for compliance with all the requirements of this part, including the employee assistance program;

(2) The name and address of each laboratory that analyzes the specimens collected for drug testing;

(3) The name and address of the operator's Medical Review Officer, and Substance Abuse Professional; and

(4) Procedures for notifying employees of the coverage and provisions of the plan.

(b) The Associate Administrator or the State Agency that has submitted a current certification under the pipeline safety laws (49 U.S.C. 60101 *et seq.*) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

[53 FR 47096, Nov. 21, 1988, as amended by Amdt. 199-2, 54 FR 51850, Dec. 18, 1989; Amdt. 199-4, 56 FR 31091, July 9, 1991; 56 FR 41077, Aug. 19, 1991; Amdt. 199-13, 61 FR 18518, Apr. 26, 1996; Amdt. 199-15, 63 FR 36863, July 8, 1998. Redesignated by Amdt. 199-19, 66 FR 47118, Sept. 11, 2001; Amdt. 199-25, 78 FR 58915, Sept. 25, 2013]

§ 199.103 Use of persons who fail or refuse a drug test.

(a) An operator may not knowingly use as an employee any person who—

(1) Fails a drug test required by this part and the medical review officer makes a determination under DOT Procedures; or

(2) Refuses to take a drug test required by this part.

(b) Paragraph (a)(1) of this section does not apply to a person who has—

(1) Passed a drug test under DOT Procedures;

(2) Been considered by the medical review officer in accordance with DOT Procedures and been determined by a substance abuse professional to have successfully completed required education or treatment; and

(3) Not failed a drug test required by this part after returning to duty.

[53 FR 47096, Nov. 21, 1988, as amended by Amdt. 199-2, 54 FR 51850, Dec. 18, 1989. Redesignated and amended by Amdt. 199-19, 66 FR 47118, Sept. 11, 2001]

§ 199.105 Drug tests required.

Each operator shall conduct the following drug tests for the presence of a prohibited drug:

(a) *Pre-employment testing.* No operator may hire or contract for the use of any person as an employee unless that person passes a drug test or is covered by an anti-drug program that conforms to the requirements of this part.

(b) *Post-accident testing.* (1) As soon as possible but no later than 32 hours after an accident, an operator must drug test each surviving covered employee whose performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. An operator may decide not to test under this paragraph but such a decision must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident.

(2) If a test required by this section is not administered within the 32 hours following the accident, the operator must prepare and maintain its decision stating the reasons why the test was not promptly administered. If a test required by paragraph (b)(1) of this section is not administered within 32 hours following the accident, the operator must cease attempts to administer a drug test and must state in the record the reasons for not administering the test.

(c) *Random testing*. (1) Except as provided in paragraphs (c)(2) through (4) of this section, the minimum annual percentage rate for random drug testing shall be 50 percent of covered employees.

(2) The Administrator's decision to increase or decrease the minimum annual percentage rate for random drug testing is based on the reported positive rate for the entire industry. All information used for this determination is drawn from the drug MIS reports required by this subpart. In order to ensure reliability of the data, the Administrator considers the quality and completeness of the reported data, may obtain additional information or reports from operators, and may make appropriate modifications in calculating the industry positive rate. Each year, the Administrator will publish in the FEDERAL REGISTER the minimum annual percentage rate for random drug testing of covered employees. The new minimum annual percentage rate for random drug testing will be applicable starting January 1 of the calendar year following publication.

(3) When the minimum annual percentage rate for random drug testing is 50 percent, the Administrator may lower this rate to 25 percent of all covered employees if the Administrator determines that the data received under the reporting requirements of § 199.119 for two consecutive calendar years indicate that the reported positive rate is less than 1.0 percent.

(4) When the minimum annual percentage rate for random drug testing is 25 percent, and the data received under the reporting requirements of § 199.119 for any calendar year indicate that the reported positive rate is equal to or greater than 1.0 percent, the Administrator will increase the minimum annual percentage rate for random drug testing to 50 percent of all covered employees.

(5) The selection of employees for random drug testing shall be made by a scientifically valid method, such as a random number table or a computer-based random number generator that is matched with employees' Social Security numbers, payroll identification numbers, or other comparable identifying numbers. Under the selection process used, each covered employee shall have an equal chance of being tested each time selections are made.

(6) The operator shall randomly select a sufficient number of covered employees for testing during each calendar year to equal an annual rate not less than the minimum annual percentage rate for random drug testing determined by the Administrator. If the operator conducts random drug testing through a consortium, the number of employees to be tested may be calculated for each individual operator or may be based on the total number of covered employees covered by the consortium who are subject to random drug testing at the same minimum annual percentage rate under this subpart or any DOT drug testing rule.

(7) Each operator shall ensure that random drug tests conducted under this subpart are unannounced and that the dates for administering random tests are spread reasonably throughout the calendar year.

(8) If a given covered employee is subject to random drug testing under the drug testing rules of more than one DOT agency for the same operator, the employee shall be subject to random drug testing at the percentage rate established for the calendar year by the DOT agency regulating more than 50 percent of the employee's function.

(9) If an operator is required to conduct random drug testing under the drug testing rules of more than one DOT agency, the operator may—

(i) Establish separate pools for random selection, with each pool containing the covered employees who are subject to testing at the same required rate; or

(ii) Randomly select such employees for testing at the highest percentage rate established for the calendar year by any DOT agency to which the operator is subject.

(d) *Testing based on reasonable cause*. Each operator shall drug test each employee when there is reasonable cause to believe the employee is using a prohibited drug. The decision to test must be based on a reasonable and articulable belief that the employee is using a prohibited drug on the basis of specific, contemporaneous physical, behavioral, or performance indicators of probable drug use. At least two of the employee's supervisors, one of whom is trained in detection of the possible symptoms of drug use, shall substantiate and concur in the decision to test an employee. The concurrence between the two supervisors may be by telephone. However, in the case of operators with 50 or fewer employees subject to testing under this part, only one supervisor of the employee trained in detecting possible drug use symptoms shall substantiate the decision to test.

(e) *Return-to-duty testing.* A covered employee who refuses to take or has a positive drug test may not return to duty in the covered function until the covered employee has complied with applicable provisions of DOT Procedures concerning substance abuse professionals and the return-to-duty process.

(f) *Follow-up testing.* A covered employee who refuses to take or has a positive drug test shall be subject to unannounced follow-up drug tests administered by the operator following the covered employee's return to duty. The number and frequency of such follow-up testing shall be determined by a substance abuse professional, but shall consist of at least six tests in the first 12 months following the covered employee's return to duty. In addition, follow-up testing may include testing for alcohol as directed by the substance abuse professional, to be performed in accordance with 49 CFR part 40. Follow-up testing shall not exceed 60 months from the date of the covered employee's return to duty. The substance abuse professional may terminate the requirement for follow-up testing at any time after the first six tests have been administered, if the substance abuse professional determines that such testing is no longer necessary.

[53 FR 47096, Nov. 21, 1988, as amended by Amdt. 199-2, 54 FR 51850, Dec. 18, 1989; 59 FR 62227, Dec. 2, 1994; Amdt. 199-15, 63 FR 13000, Mar. 17, 1998; Amdt. 199-15, 63 FR 36863, July 8, 1998. Redesignated and amended by Amdt. 199-19, 66 FR 47118, Sept. 11, 2001; Amdt. 199-27, 82 FR 8001, Jan. 23, 2017]

§ 199.107 Drug testing laboratory.

(a) Each operator shall use for the drug testing required by this part only drug testing laboratories certified by the Department of Health and Human Services under the DOT Procedures.

(b) The drug testing laboratory must permit—

(1) Inspections by the operator before the laboratory is awarded a testing contract; and

(2) Unannounced inspections, including examination of records, at any time, by the operator, the Administrator, and if the operator is subject to state agency jurisdiction, a representative of that state agency.

[53 FR 47096, Nov. 21, 1988. Redesignated by Amdt. 199-19, 66 FR 47118, Sept. 11, 2001]

§ 199.109 Review of drug testing results.

(a) *MRO appointment.* Each operator shall designate or appoint a medical review officer (MRO). If an operator does not have a qualified individual on staff to serve as MRO, the operator may contract for the provision of MRO services as part of its anti-drug program.

(b) *MRO qualifications.* Each MRO must be a licensed physician who has the qualifications required by DOT Procedures.

(c) *MRO duties.* The MRO must perform functions for the operator as required by DOT Procedures.

(d) *MRO reports.* The MRO must report all drug test results to the operator in accordance with DOT Procedures.

(e) Evaluation and rehabilitation may be provided by the operator, by a substance abuse professional under contract with the operator, or by a substance abuse professional not affiliated with the operator. The choice of substance abuse professional and assignment of costs shall be made in accordance with the operator/employee agreements and operator/employee policies.

(f) The operator shall ensure that a substance abuse professional, who determines that a covered employee requires assistance in resolving problems with drug abuse, does not refer the covered employee to the substance abuse professional's private practice or to a person or organization from which the substance abuse professional receives remuneration or in which the substance abuse professional has a financial interest. This paragraph does not prohibit a substance abuse professional from referring a covered employee for assistance provided through:

(1) A public agency, such as a State, county, or municipality;

(2) The operator or a person under contract to provide treatment for drug problems on behalf of the operator;

(3) The sole source of therapeutically appropriate treatment under the employee's health insurance program; or

(4) The sole source of therapeutically appropriate treatment reasonably accessible to the employee.

[53 FR 47096, Nov. 21, 1988, as amended by Amdt. 199–2, 54 FR 51850, Dec. 18, 1989; Amdt. 199–15, 63 FR 13000, Mar. 17, 1998; Amdt. 199–15, 63 FR 36863, July 8, 1998. Redesignated and amended by Amdt. 199–19, 66 FR 47118, Sept. 11, 2001]

§ 199.111 [Reserved]

§ 199.113 Employee assistance program.

(a) Each operator shall provide an employee assistance program (EAP) for its employees and supervisory personnel who will determine whether an employee must be drug tested based on reasonable cause. The operator may establish the EAP as a part of its internal personnel services or the operator may contract with an entity that provides EAP services. Each EAP must include education and training on drug use. At the discretion of the operator, the EAP may include an opportunity for employee rehabilitation.

(b) Education under each EAP must include at least the following elements: display and distribution of informational material; display and distribution of a community service hot-line telephone number for employee assistance; and display and distribution of the employer's policy regarding the use of prohibited drugs.

(c) Training under each EAP for supervisory personnel who will determine whether an employee must be drug tested based on reasonable cause must include one 60-minute period of training on the specific, contemporaneous physical, behavioral, and performance indicators of probable drug use.

[53 FR 47096, Nov. 21, 1988. Redesignated by Amdt. 199–19, 66 FR 47118, Sept. 11, 2001]

§ 199.115 Contractor employees.

With respect to those employees who are contractors or employed by a contractor, an operator may provide by contract that the drug testing, education, and training required by this part be carried out by the contractor provided:

(a) The operator remains responsible for ensuring that the requirements of this part are complied with; and

(b) The contractor allows access to property and records by the operator, the Administrator, and if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purpose of monitoring the operator's compliance with the requirements of this part.

[53 FR 47096, Nov. 21, 1988. Redesignated by Amdt. 199–19, 66 FR 47118, Sept. 11, 2001]

§ 199.117 Recordkeeping.

(a) Each operator shall keep the following records for the periods specified and permit access to the records as provided by paragraph (b) of this section:

(1) Records that demonstrate the collection process conforms to this part must be kept for at least 3 years.

(2) Records of employee drug test that indicate a verified positive result, records that demonstrate compliance with the recommendations of a substance abuse professional, and MIS annual report data shall be maintained for a minimum of five years.

(3) Records of employee drug test results that show employees passed a drug test must be kept for at least 1 year.

(4) Records confirming that supervisors and employees have been trained as required by this part must be kept for at least 3 years.

(5) Records of decisions not to administer post-accident employee drug tests must be kept for at least 3 years.

(b) Information regarding an individual's drug testing results or rehabilitation must be released upon the written consent of the individual and as provided by DOT Procedures. Statistical data related to drug testing and rehabilitation that is not name-specific and training records must be made available to the Administrator or the representative of a state agency upon request.

[53 FR 47096, Nov. 21, 1988, as amended at 58 FR 68260, Dec. 23, 1993. Redesignated and amended by Amdt. 199-19, 66 FR 47119, Sept. 11, 2001; 68 FR 75465, Dec. 31, 2003; Amdt. 199-27, 82 FR 8001, Jan. 23, 2017]

§ 199.119 Reporting of anti-drug testing results.

(a) Each large operator (having more than 50 covered employees) must submit an annual Management Information System (MIS) report to PHMSA of its anti-drug testing using the MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40), not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (*https://portal.phmsa.dot.gov/phmsaportallanding*) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA.

(b) Each report required under this section must be submitted electronically at *http://damis.dot.gov*. An operator may obtain the user name and password needed for electronic reporting from the PHMSA Portal (*https://portal.phmsa.dot.gov/phmsaportallanding*). If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to *informationresourcesmanager@dot.gov* to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

(c) To calculate the total number of covered employees eligible for random testing throughout the year, as an operator, you must add the total number of covered employees eligible for testing during each random testing period for the year and divide that total by the number of random testing periods. Covered employees, and only covered employees, are to be in an employer's random testing pool, and all covered employees must be in the random pool. If you are an employer conducting random testing more often than once per month (e.g., you select daily, weekly, bi-weekly), you do not need to compute this total number of covered employees rate more than on a once per month basis.

(d) As an employer, you may use a service agent (e.g., C/TPA) to perform random selections for you; and your covered employees may be part of a larger random testing pool of covered employees. However, you must ensure that the service agent you use is testing at the appropriate percentage established for your industry and that only covered employees are in the random testing pool.

(e) Each operator that has a covered employee who performs multi-DOT agency functions (e.g., an employee performs pipeline maintenance duties and drives a commercial motor vehicle), count the employee only on the MIS report for the DOT agency under which he or she is randomly tested. Normally, this will be the DOT agency under which the employee performs more than 50% of his or her duties. Operators may have to explain the testing data for these employees in the event of a DOT agency inspection or audit.

(f) A service agent (e.g., Consortia/Third Party Administrator as defined in 49 CFR part 40) may prepare the MIS report on behalf of an operator. However, each report shall be certified by the operator's anti-drug manager or designated representative for accuracy and completeness.

[68 FR 75465, Dec. 31, 2003, as amended by Amdt. 199-20, 69 FR 32898, June 14, 2004; 70 FR 11140, Mar. 8, 2005; 73 FR 16571, Mar. 28, 2008; Amdt. 199-27, 82 FR 8001, Jan. 23, 2017]

Subpart C—Alcohol Misuse Prevention Program

SOURCE: Amdt. 199–9, 59 FR 7430, Feb. 15, 1994, unless otherwise noted. Redesignated by Amdt. 199–19, 66 FR 47118, Sept. 11, 2001.

§ 199.200 Purpose.

The purpose of this subpart is to establish programs designed to help prevent accidents and injuries resulting from the misuse of alcohol by employees who perform covered functions for operators of oertain pipeline facilities subject to parts 192, 193, or 195 of this chapter.

§ 199.201 [Reserved]

§ 199.202 Alcohol misuse plan.

Each operator must maintain and follow a written alcohol misuse plan that conforms to the requirements of this part and DOT Procedures concerning alcohol testing programs. The plan shall contain methods and procedures for compliance with all the requirements of this subpart, including required testing, recordkeeping, reporting, education and training elements.

[Amdt. 199–9, 59 FR 7430, Feb. 15, 1994, as amended by Amdt. 199–19, 66 FR 47119, Sept. 11, 2001]

§§ 199.203–199.205 [Reserved]

§ 199.209 Other requirements imposed by operators.

(a) Except as expressly provided in this subpart, nothing in this subpart shall be construed to affect the authority of operators, or the rights of employees, with respect to the use or possession of alcohol, including authority and rights with respect to alcohol testing and rehabilitation.

(b) Operators may, but are not required to, conduct pre-employment alcohol testing under this subpart. Each operator that conducts pre-employment alcohol testing must—

(1) Conduct a pre-employment alcohol test before the first performance of covered functions by every covered employee (whether a new employee or someone who has transferred to a position involving the performance of covered functions);

(2) Treat all covered employees the same for the purpose of pre-employment alcohol testing (*i.e.*, you must not test some covered employees and not others);

(3) Conduct the pre-employment tests after making a contingent offer of employment or transfer, subject to the employee passing the pre-employment alcohol test;

(4) Conduct all pre-employment alcohol tests using the alcohol testing procedures in DOT Procedures; and

(5) Not allow any covered employee to begin performing covered functions unless the result of the employee's test indicates an alcohol concentration of less than 0.04.

[Amdt. 199–9, 59 FR 7430, Feb. 15, 1994, as amended by Amdt. 199–19, 66 FR 47119, Sept. 11, 2001]

§ 199.211 Requirement for notice.

Before performing an alcohol test under this subpart, each operator shall notify a covered employee that the alcohol test is required by this subpart. No operator shall falsely represent that a test is administered under this subpart.

§ 199.213 [Reserved]

§ 199.215 Alcohol concentration.

Each operator shall prohibit a covered employee from reporting for duty or remaining on duty requiring the performance of covered functions while having an alcohol concentration of 0.04 or greater. No operator having actual knowledge that a covered employee has an alcohol concentration of 0.04 or greater shall permit the employee to perform or continue to perform covered functions.

§ 199.217 On-duty use.

Each operator shall prohibit a covered employee from using alcohol while performing covered functions. No operator having actual knowledge that a covered employee is using alcohol while performing covered functions shall permit the employee to perform or continue to perform covered functions.

§ 199.219 Pre-duty use.

Each operator shall prohibit a covered employee from using alcohol within four hours prior to performing covered functions, or, if an employee is called to duty to respond to an emergency, within the time period after the employee has been notified to report for duty. No operator having actual knowledge that a covered employee has used alcohol within four hours prior to performing covered functions or within the time period after the employee has been notified to report for duty shall permit that covered employee to perform or continue to perform covered functions.

§ 199.221 Use following an accident.

Each operator shall prohibit a covered employee who has actual knowledge of an accident in which his or her performance of covered functions has not been discounted by the operator as a contributing factor to the accident from using alcohol for eight hours following the accident, unless he or she has been given a post-accident test under § 199.225(a), or the operator has determined that the employee's performance could not have contributed to the accident.

§ 199.223 Refusal to submit to a required alcohol test.

Each operator shall require a covered employee to submit to a post-accident alcohol test required under § 199.225(a), a reasonable suspicion alcohol test required under § 199.225(b), or a follow-up alcohol test required under § 199.225(d). No operator shall permit an employee who refuses to submit to such a test to perform or continue to perform covered functions.

§ 199.225 Alcohol tests required.

Each operator must conduct the following types of alcohol tests for the presence of alcohol:

(a) *Post-accident.* (1) As soon as practicable following an accident, each operator must test each surviving covered employee for alcohol if that employee's performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. The decision not to administer a test under this section must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident.

(2)(i) If a test required by this section is not administered within 2 hours following the accident, the operator shall prepare and maintain on file a record stating the reasons the test was not promptly administered. If a test required by paragraph (a) is not administered within 8 hours following the accident, the operator shall cease attempts to administer an alcohol test and shall state in the record the reasons for not administering the test.

(ii) [Reserved]

(3) A covered employee who is subject to post-accident testing who fails to remain readily available for such testing, including notifying the operator or operator representative of his/her location if he/she leaves the scene of the accident prior to submission to such test, may be deemed by the operator to have refused to submit to testing. Nothing in this section shall be construed to require the delay of necessary medical attention for injured people following an accident or to prohibit a covered employee from leaving the scene of an accident for the period necessary to obtain assistance in responding to the accident or to obtain necessary emergency medical care.

(b) *Reasonable suspicion testing.* (1) Each operator shall require a covered employee to submit to an alcohol test when the operator has reasonable suspicion to believe that the employee has violated the prohibitions in this subpart.

(2) The operator's determination that reasonable suspicion exists to require the covered employee to undergo an alcohol test shall be based on specific, contemporaneous, articulable observations concerning the appearance, behavior, speech, or body odors of the employee. The required observations shall be made by a supervisor who is trained in detecting the symptoms of alcohol misuse. The supervisor who makes the determination that reasonable suspicion exists shall not conduct the breath alcohol test on that employee.

(3) Alcohol testing is authorized by this section only if the observations required by paragraph (b)(2) of this section are made during, just preceding, or just after the period of the work day that the employee is required to be in compliance with this subpart. A covered employee may be directed by the operator to undergo reasonable suspicion testing for alcohol only while the employee is performing covered functions; just before the employee is to perform covered functions; or just after the employee has ceased performing covered functions.

(4)(i) If a test required by this section is not administered within 2 hours following the determination under paragraph (b)(2) of this section, the operator shall prepare and maintain on file a record stating the reasons the test was not promptly administered. If a test required by this section is not administered within 8 hours following the determination under paragraph (b)(2) of this section, the operator shall cease attempts to administer an alcohol test and shall state in the record the reasons for not administering the test. Records shall be submitted to PHMSA upon request of the Administrator.

(ii) [Reserved]

(iii) Notwithstanding the absence of a reasonable suspicion alcohol test under this section, an operator shall not permit a covered employee to report for duty or remain on duty requiring the performance of covered functions while the employee is under the influence of or impaired by alcohol, as shown by the behavioral, speech, or performance indicators of alcohol misuse, nor shall an operator permit the covered employee to perform or continue to perform covered functions, until:

(A) An alcohol test is administered and the employee's alcohol concentration measures less than 0.02; or

(B) The start of the employee's next regularly scheduled duty period, but not less than 8 hours following the determination under paragraph (b)(2) of this section that there is reasonable suspicion to believe that the employee has violated the prohibitions in this subpart.

(iv) Except as provided in paragraph (b)(4)(ii), no operator shall take any action under this subpart against a covered employee based solely on the employee's behavior and appearance in the absence of an alcohol test. This does not prohibit an operator with the authority independent of this subpart from taking any action otherwise consistent with law.

(c) *Return-to-duty testing.* Each operator shall ensure that before a covered employee returns to duty requiring the performance of a covered function after engaging in conduct prohibited by §§ 199.215 through 199.223, the employee shall undergo a return-to-duty alcohol test with a result indicating an alcohol concentration of less than 0.02.

(d) *Follow-up testing.* (1) Following a determination under § 199.243(b) that a covered employee is in need of assistance in resolving problems associated with alcohol misuse, each operator shall ensure that the employee is subject to unannounced follow-up alcohol testing as directed by a substance abuse professional in accordance with the provisions of § 199.243(c)(2)(ii).

(2) Follow-up testing shall be conducted when the covered employee is performing covered functions; just before the employee is to perform covered functions; or just after the employee has ceased performing such functions.

(e) *Retesting of covered employees with an alcohol concentration of 0.02 or greater but less than 0.04.* Each operator shall retest a covered employee to ensure compliance with the provisions of § 199.237, if an operator chooses to permit the employee to perform a covered function within 8 hours following the administration of an alcohol test indicating an alcohol concentration of 0.02 or greater but less than 0.04.

[Amdt. 199–9, 59 FR 7430, Feb. 15, 1994, as amended at 59 FR 62239, 62246, Dec. 2, 1994; Redesignated by Amdt. 199–19, 66 FR 47119, Sept. 11, 2001; 70 FR 11140, March 8, 2005; Amdt. 199–27, 82 FR 8001, Jan. 23, 2017]

§ 199.227 Retention of records.

(a) *General requirement.* Each operator shall maintain records of its alcohol misuse prevention program as provided in this section. The records shall be maintained in a secure location with controlled access.

(b) *Period of retention*. Each operator shall maintain the records in accordance with the following schedule:

(1) *Five years*. Records of employee alcohol test results with results indicating an alcohol concentration of 0.02 or greater, documentation of refusals to take required alcohol tests, calibration documentation, employee evaluation and referrals, and MIS annual report data shall be maintained for a minimum of five years.

(2) *Two years*. Records related to the collection process (except calibration of evidential breath testing devices), and training shall be maintained for a minimum of two years.

(3) *One year*. Records of all test results below 0.02 (as defined in 49 CFR part 40) shall be maintained for a minimum of one year.

(4) *Three years*. Records of decisions not to administer post-accident employee alcohol tests must be kept for a minimum of three years.

(c) *Types of records*. The following specific records shall be maintained:

(1) Records related to the collection process:

(i) Collection log books, if used.

(ii) Calibration documentation for evidential breath testing devices.

(iii) Documentation of breath alcohol technician training.

(iv) Documents generated in connection with decisions to administer reasonable suspicion alcohol tests.

(v) Documents generated in connection with decisions on post- accident tests.

(vi) Documents verifying existence of a medical explanation of the inability of a covered employee to provide adequate breath for testing.

(2) Records related to test results:

(i) The operator's copy of the alcohol test form, including the results of the test.

(ii) Documents related to the refusal of any covered employee to submit to an alcohol test required by this subpart.

(iii) Documents presented by a covered employee to dispute the result of an alcohol test administered under this subpart.

(3) Records related to other violations of this subpart.

(4) Records related to evaluations:

(i) Records pertaining to a determination by a substance abuse professional concerning a covered employee's need for assistance.

(ii) Records concerning a covered employee's compliance with the recommendations of the substance abuse professional.

(5) Record(s) related to the operator's MIS annual testing data.

(6) Records related to education and training:

(i) Materials on alcohol misuse awareness, including a copy of the operator's policy on alcohol misuse.

(ii) Documentation of compliance with the requirements of § 199.231.

(iii) Documentation of training provided to supervisors for the purpose of qualifying the supervisors to make a determination concerning the need for alcohol testing based on reasonable suspicion.

(iv) Certification that any training conducted under this subpart complies with the requirements for such training.

[Amdt. 199-9, 59 FR 7430, Feb. 15, 1994, unless otherwise noted. Redesignated by Amdt. 199-19, 66 FR 47118, Sept. 11, 2001, as amended by Amdt. 199-27, 82 FR 8001, Jan. 23, 2017]

§ 199.229 Reporting of alcohol testing results.

(a) Each large operator (having more than 50 covered employees) must submit an annual MIS report to PHMSA of its alcohol testing results using the MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40), not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (*https://portal.phmsa.dot.gov/phmsaportallanding*) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA.

(b) Each operator that has a covered employee who performs multi-DOT agency functions (e.g., an employee performs pipeline maintenance duties and drives a commercial motor vehicle), count the employee only on the MIS report for the DOT agency under which he or she is tested. Normally, this will be the DOT agency under which the employee performs more than 50% of his or her duties. Operators may have to explain the testing data for these employees in the event of a DOT agency inspection or audit.

(c) Each report required under this section must be submitted electronically at *http://damis.dot.gov*. An operator may obtain the user name and password needed for electronic reporting from the PHMSA Portal (*https://portal.phmsa.dot.gov/phmsaportallanding*). If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202–366–8075, or electronically to *informationresourcesmanager@dot.gov* to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

(d) A service agent (e.g., Consortia/Third Party Administrator as defined in part 40) may prepare the MIS report on behalf of an operator. However, each report shall be certified by the operator's anti-drug manager or designated representative for accuracy and completeness.

[68 FR 75466, Dec. 31, 2003, as amended by Amdt. 199–20, 69 FR 32898, June 14, 2004; 70 FR 11140, Mar. 8, 2005; 73 FR 16571, Mar. 28, 2008; 74 FR 2895, Jan. 16, 2009; Amdt. 199–27, 82 FR 8001, Jan. 23, 2017]

§ 199.231 Access to facilities and records.

(a) Except as required by law or expressly authorized or required in this subpart, no employer shall release covered employee information that is contained in records required to be maintained in § 199.227.

(b) A covered employee is entitled, upon written request, to obtain copies of any records pertaining to the employee's use of alcohol, including any records pertaining to his or her alcohol tests. The operator shall promptly provide the records requested by the employee. Access to an employee's records shall not be contingent upon payment for records other than those specifically requested.

(c) Each operator shall permit access to all facilities utilized in complying with the requirements of this subpart to the Secretary of Transportation, any DOT agency, or a representative of a state agency with regulatory authority over the operator.

(d) Each operator shall make available copies of all results for employer alcohol testing conducted under this subpart and any other information pertaining to the operator's alcohol misuse prevention program, when requested by the Secretary of Transportation, any DOT agency with regulatory authority over the operator, or a representative of a state agency with regulatory authority over the operator. The information shall include name-specific alcohol test results, records, and reports.

(e) When requested by the National Transportation Safety Board as part of an accident investigation, an operator shall disclose information related to the operator's administration of any post- accident alcohol tests administered following the accident under investigation.

(f) An operator shall make records available to a subsequent employer upon receipt of the written request from the covered employee. Disclosure by the subsequent employer is permitted only as expressly authorized by the terms of the employee's written request.

(g) An operator may disclose information without employee consent as provided by DOT Procedures concerning certain legal proceedings.

(h) An operator shall release information regarding a covered employee's records as directed by the specific, written consent of the employee authorizing release of the information to an identified person. Release of such information by the person receiving the information is permitted only in accordance with the terms of the employee's consent.

[Amdt. 199-9, 59 FR 7430, Feb. 15, 1994, as amended by Amdt. 199-19, 66 FR 47119, Sept. 11, 2001]

§ 199.233 Removal from covered function.

Except as provided in §§ 199.239 through 199.243, no operator shall permit any covered employee to perform covered functions if the employee has engaged in conduct prohibited by §§ 199.215 through 199.223 or an alcohol misuse rule of another DOT agency.

§ 199.235 Required evaluation and testing.

No operator shall permit a covered employee who has engaged in conduct prohibited by §§ 199.215 through 199.223 to perform covered functions unless the employee has met the requirements of § 199.243.

§ 199.237 Other alcohol-related conduct.

(a) No operator shall permit a covered employee tested under the provisions of § 199.225, who is found to have an alcohol concentration of 0.02 or greater but less than 0.04, to perform or continue to perform covered functions, until:

(1) The employee's alcohol concentration measures less than 0.02 in accordance with a test administered under § 199.225(e); or

(2) The start of the employee's next regularly scheduled duty period, but not less than eight hours following administration of the test.

(b) Except as provided in paragraph (a) of this section, no operator shall take any action under this subpart against an employee based solely on test results showing an alcohol concentration less than 0.04. This does not prohibit an operator with authority independent of this subpart from taking any action otherwise consistent with law.

§ 199.239 Operator obligation to promulgate a policy on the misuse of alcohol.

(a) *General requirements.* Each operator shall provide educational materials that explain these alcohol misuse requirements and the operator's policies and procedures with respect to meeting those requirements.

(1) The operator shall ensure that a copy of these materials is distributed to each covered employee prior to start of alcohol testing under this subpart, and to each person subsequently hired for or transferred to a covered position.

(2) Each operator shall provide written notice to representatives of employee organizations of the availability of this information.

(b) *Required content.* The materials to be made available to covered employees shall include detailed discussion of at least the following:

(1) The identity of the person designated by the operator to answer covered employee questions about the materials.

(2) The categories of employees who are subject to the provisions of this subpart.

(3) Sufficient information about the covered functions performed by those employees to make clear what period of the work day the covered employee is required to be in compliance with this subpart.

(4) Specific information concerning covered employee conduct that is prohibited by this subpart.

(5) The circumstances under which a covered employee will be tested for alcohol under this subpart.

(6) The procedures that will be used to test for the presence of alcohol, protect the covered employee and the integrity of the breath testing process, safeguard the validity of the test results, and ensure that those results are attributed to the correct employee.

(7) The requirement that a covered employee submit to alcohol tests administered in accordance with this subpart.

(8) An explanation of what constitutes a refusal to submit to an alcohol test and the attendant consequences.

(9) The consequences for covered employees found to have violated the prohibitions under this subpart, including the requirement that the employee be removed immediately from covered functions, and the procedures under § 199.243.

(10) The consequences for covered employees found to have an alcohol concentration of 0.02 or greater but less than 0.04.

(11) Information concerning the effects of alcohol misuse on an individual's health, work, and personal life; signs and symptoms of an alcohol problem (the employee's or a coworker's); and including intervening evaluating and resolving problems associated with the misuse of alcohol including intervening when an alcohol problem is suspected, confrontation, referral to any available EAP, and/or referral to management.

(c) *Optional provisions*. The materials supplied to covered employees may also include information on additional operator policies with respect to the use or possession of alcohol, including any consequences for an employee found to have a specified alcohol level, that are based on the operator's authority independent of this subpart. Any such additional policies or consequences shall be clearly described as being based on independent authority.

§ 199.241 Training for supervisors.

Each operator shall ensure that persons designated to determine whether reasonable suspicion exists to require a covered employee to undergo alcohol testing under § 199.225(b) receive at least 60 minutes of training on the physical, behavioral, speech, and performance indicators of probable alcohol misuse.

§ 199.243 Referral, evaluation, and treatment.

(a) Each covered employee who has engaged in conduct prohibited by §§ 199.215 through 199.223 of this subpart shall be advised of the resources available to the covered employee in evaluating and resolving problems associated with the misuse of alcohol, including the names, addresses, and telephone numbers of substance abuse professionals and counseling and treatment programs.

(b) Each covered employee who engages in conduct prohibited under §§ 199.215 through 199.223 shall be evaluated by a substance abuse professional who shall determine what assistance, if any, the employee needs in resolving problems associated with alcohol misuse.

(c)(1) Before a covered employee returns to duty requiring the performance of a covered function after engaging in conduct prohibited by §§ 199.215 through 199.223 of this subpart, the employee shall undergo a return-to-duty alcohol test with a result indicating an alcohol concentration of less than 0.02.

(2) In addition, each covered employee identified as needing assistance in resolving problems associated with alcohol misuse—

(i) Shall be evaluated by a substance abuse professional to determine that the employee has properly followed any rehabilitation program prescribed under paragraph (b) of this section, and

(ii) Shall be subject to unannounced follow-up alcohol tests administered by the operator following the employee's return to duty. The number and frequency of such follow-up testing shall be determined by a substance abuse professional, but shall consist of at least six tests in the first 12 months following the employee's return to duty. In addition, follow-up testing may include testing for drugs, as directed by the substance abuse professional, to be performed in accordance with 49 CFR part 40. Follow-up testing shall not exceed 60 months from the date of the employee's return to duty. The substance abuse professional may terminate the requirement for follow-up testing at any time after the first six tests have been administered, if the substance abuse professional determines that such testing is no longer necessary.

(d) Evaluation and rehabilitation may be provided by the operator, by a substance abuse professional under contract with the operator, or by a substance abuse professional not affiliated with the operator. The choice of substance abuse professional and assignment of costs shall be made in accordance with the operator/employee agreements and operator/employee policies.

(e) The operator shall ensure that a substance abuse professional who determines that a covered employee requires assistance in resolving problems with alcohol misuse does not refer the employee to the substance abuse professional's private practice or to a person or organization from which the substance abuse professional receives remuneration or in which the substance abuse professional has a financial interest. This paragraph does not prohibit a substance abuse professional from referring an employee for assistance provided through—

(1) A public agency, such as a State, county, or municipality;

(2) The operator or a person under contract to provide treatment for alcohol problems on behalf of the operator;

(3) The sole source of therapeutically appropriate treatment under the employee's health insurance program; or

(4) The sole source of therapeutically appropriate treatment reasonably accessible to the employee.

§ 199.245 Contractor employees.

(a) With respect to those covered employees who are contractors or employed by a contractor, an operator may provide by contract that the alcohol testing, training and education required by this subpart be carried out by the contractor provided:

(b) The operator remains responsible for ensuring that the requirements of this subpart and part 40 of this title are complied with; and

(c) The contractor allows access to property and records by the operator, the Administrator, any DOT agency with regulatory authority over the operator or covered employee, and, if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purposes of monitoring the operator's compliance with the requirements of this subpart and part 40 of this title.