GAS PIPING technology committee

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Dear *Guide* Purchaser,

Enclosed is Addendum 1 to ANSI GPTC Z380.1, *Guide for Gas Transmission, Distribution and Gathering Piping Systems,* 2022 Edition. Addenda are formatted to enable the replacement of pages in your *Guide* with the updated enclosed pages. Please follow the enclosed page replacement instructions.

On behalf of the Gas Piping Technology Committee and the American Gas Association, thank you for your purchase and interest in the *Guide*.

Sincerely,

Betsy Carter

Secretary
GPTC Z380

# GPTC GUIDE FOR GAS TRANSMISSION, DISTRIBUTION, AND GATHERING PIPING SYSTEMS

## 2022 EDITION

## ADDENDUM 1, JUNE 2022

The changes in this addendum are marked by wide vertical lines inserted to the left of modified text, overwriting the left border of most tables, or a block symbol ( ▌) where needed. There was one Federal Regulation updates for this period. 11 GPTC transactions affected 17 sections of the Guide.

Editorial updates include application of the Editorial Guidelines, adjustments to page numbering, and adjustment of text on pages. While only significant editorial updates are marked, all affected pages carry the current addendum footnote. Editorial updates as indicated "EU" affected one section of the Guide (plus other sections impacted by page adjustments, etc.).

The table shows the affected sections, the pages to be removed, and their replacement pages.

| Key to Reasons for Change |
|---|
| Amdt.19X-XXX or docket number: federal regulation amendment<br>TRYY-XX: GPTC transaction with new or updated guide material<br>EU: editorial update |

| Guide Section | Reason for Change | Pages to be Removed | Replacement Pages |
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| Title Page | EU | iii- thru xii(a) | iii- thru xii(a) |

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(c) Section 191.5 states that an operator must confirm or revise the initial telephonic or electronic notice within 48 hours of the initial notice to the extent practicable. Updates may include revisions to the amount of gas released, number of fatalities or injuries, property damage, or other significant facts. The operator should clearly report to the NRC that additional information is being provided and give the NRC the initial notice's assigned NRC Report Number. The follow-up report may result in an additional NRC Report Number for the operator.

(d) All related NRC Report Numbers should be referenced in the PHMSA-OPS electronic or written incident report (see §§191.9 and 191.15).

(e) If an operator determines that an event for which an NRC notice has been made does not meet the PHMSA definition of an incident, and no 30-day report has been submitted, the operator is encouraged (but not required) to provide notification of that determination to the PHMSA Accident Investigation Division and to the state pipeline regulatory authority (if the event is investigated by the state). The e-mail address for the Accident Investigation Division is PHMSAAccidentInvestigationDivision@dot.gov.

(f) If a 30-day incident report has been made as required in §191.9 (Form PHMSA F 7100.1) or §191.15 (Form PHMSA F7100.2) and further investigation reveals that the event was not an "incident," and therefore not reportable, the operator may request that their report be retracted. The Instructions for Form PHMSA F7100.1 and Form PHMSA F7100.2 state that requests are to be sent to the Information Resources Manager at the address specified in §191.7 or emailed to InformationResourcesManager@dot.gov. The instructions further state that requests are to include the following.
   (1) The Report ID (the unique 8-digit identifier assigned by PHMSA).
   (2) Operator name.
   (3) PHMSA-issued OPID number.
   (4) The number assigned by the NRC when an immediate notice was made in accordance with §191.5. If supplemental reports were made to the NRC for the event, list all NRC report numbers associated with the event.
   (5) Date of the event.
   (6) Location of the event.
   (7) A brief statement as to why the report should be retracted.

(g) For intrastate pipelines, it is necessary to comply with federal reporting requirements (§191.5) even though an "incident" (as defined in §191.3) has been reported to the appropriate state agency.

(h) The operator should consider providing (even if not required) the appropriate state agency with the same documents and reports that are provided to PHMSA.

(i) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.

## §191.7

### Report submission requirements.

*[Effective Date: 10/01/15]*

**(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.**

**[Amdt. 191-3, 46 FR 37250, July 20, 1981; Amdt. 191-4, 47 FR 32719, July 29, 1982; Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-6, 53 FR 24942, July 1, 1988 with Amdt. 191-6 Correction, 53 FR 26560, July 13, 1988; Amdt. 191-16, 69 FR 32886, June 14, 2004; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; RIN 2137-AE29, 73 FR 16562, Mar. 28, 2008; RIN 2137-AE29 (#2), 74 FR 2889, Jan. 16, 2009; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt. 191-23, 80 FR 12762, Mar. 11, 2015]**

**GUIDE MATERIAL**

For National Pipeline Mapping System submission requirements, see §191.29.

## §191.9

## Distribution system: Incident report.

*[Effective Date: 01/01/11]*

**(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. 191-3, 46 FR 37250, July 20, 1981; Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010]**

**GUIDE MATERIAL**

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.
(b) Additional state reporting requirements may exist for intrastate facilities.
(c) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.

# §191.11

## Distribution system: Annual report.

*[Effective Date: 03/12/21]*

**(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 F7100.1–1. 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, a petroleum gas system that serves fewer than 100 customers from a single source, or an individual service line directly connected to a production pipeine or a gathering line as determined in §192.8.**

**[Amdt. 191-2, 37 FR 1172, Jan. 26, 1972; Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010]**

### GUIDE MATERIAL

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website www.phmsa.dot.gov/forms/pipeline-forms.

(b) Additional state reporting requirements may exist for intrastate facilities.

# §191.12

## [Reserved]

*[Effective Date: 03/12/21]*

## §191.13

### Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines.

*[Effective Date: 06/04/84]*

**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 18956, May 3, 1984]**

**GUIDE MATERIAL**

(a) See §192.3 for definitions of *Distribution line, Gathering line, and Transmission line~~s~~.*
(b) Additional state reporting requirements may exist for intrastate facilities, but federal reports for gathering lines are based on the definitions found in §§192.8 and 192.9.

## §191.15

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

*[Effective Date: 01/18/17]*

***(a) Pipeline systems*— (1) *Transmission or regulated onshore gathering*. Each operator of a transmission pipeline system or a regulated onshore gathering pipeline system must submit Department of Transportation (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.**

**(2) Reporting-regulated gathering. Each operator of a reporting-regulated gathering pipeline system must submit DOT Form PHMSA F 7100.2-2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5 that occurs after May 16, 2022.**

**(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.**

**[Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt. 191-24, 81 FR 91871, Dec. 19, 2016; Amdt. 191-30, 86 FR 63294 Nov. 15, 2021]**

**GUIDE MATERIAL**

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms, used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.
(b) Additional state reporting requirements may exist for intrastate facilities.
(c) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.

## §191.17

## Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas facilities: Annual report.

*[Effective Date: 01/18/17]*

**(a) *Pipeline systems*– (1) *Transmission or regulated onshore gathering*. Each operator of a transmission or a regulated onshore 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.**

**(2) *Type R gathering.* Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2-3. This report must be submitted each year, not later than March 15, for the preceding calendar year.**

**(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.**

**[Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt. 191-24, 81 FR 91871, Dec. 16, 2016; Amdt. 191-30, 86 FR 63294 Nov. 15, 2021]**

**GUIDE MATERIAL**

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.
(b) Federal reports for gathering lines are based on the definitions found in §§192.8 and 192.9.
(c) Additional state reporting requirements may exist for intrastate facilities.
(d) For National Pipeline Mapping System submission requirements, see §191.29.
(e) Operators will need to reflect changes due to service conversion or product change (see §191.22(c)(1)(vi)) on subsequent Annual Reports.

## §191.21

### OMB control number assigned to information collection.

*[Effective Date: 01/18/17]*

**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. |

**[Issued by Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-13, 63 FR 7721, Feb. 17, 1998 with Amdt. 191-13 Confirmation, 63 FR 38757, July 20, 1998; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt. 191-24, 81 FR 91871, Dec. 19, 2016]**

**GUIDE MATERIAL**

No guide material necessary.

## §191.22

### National Registry of Pipeline and LNG Operators.

*[Effective Date: 03/24/17]*

**(a) OPID Request. Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, underground natural gas 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 on 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 pipeline 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 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.**

**[Issued by Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt 191-24, 81 FR 91872, Dec. 19, 2016; Amdt. 191-25, 82 FR 7997, Jan. 23, 2017 ]**

## GUIDE MATERIAL

(a) Section 191.22(c)(1) requires a notice not later than 60 days before certain construction activities occur. Examples of construction activities that might trigger this advance notification to PHMSA under §191.22(c)(1) include the following.

(1) Right-of-way clearing, grading, or ditching performed in advance of, but associated with the construction project.

(2) Onsite equipment fabrication.

(3) Onsite installation activities.

See OPS Advisory Bulletin ADB-2014-03 (79 FR 54777, Sept. 12, 2014; see Guide Material Appendix G-192-1, Section 2).

(b) Operators must notify PHMSA in accordance with §191.22(c)(1)(ii) for the construction of 10 or more miles of a new pipeline, or replacement of 10 or more contiguous miles of line pipe in an existing pipeline (see OPS Advisory Bulletin ADB-2014-03).

(c) Operators must notify PHMSA in accordance with §191.22(c)(1)(vi) when the commodity being transported changes from one listed below to another.
(1) Natural gas.
(2) Synthetic gas.
(3) Hydrogen gas.
(4) Propane gas.
(5) Landfill gas.
(6) Other gas.

(d) See guide material under §192.14 for examples of conversion of service that would also require notice to PHMSA in accordance with §191.22(c)(1)(vi).

## §191.23

### Reporting safety-related conditions.

*[Effective Date: 07/01/2020]*

**(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 impair the serviceability of a pipeline or the structural integrity or reliability of an underground natural gas facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility, 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 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—plus the margin (build-up) allowed for operation of pressure limiting or control devices—to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility, or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG.**

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

**10) For transmission pipelines only, each exceedance of maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in the applicable requirements of §§ 192.201, 192.620(e), and 192.739. The reporting requirement of this paragraph (a)(10) is not applicable to gathering lines, distribution lines, LNG facilities, or underground natural gas storage facilities (*See* paragraph (a)(6) of this section.**

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

**(1) Exists on a master meter system, a reporting-regulated gathering pipeline, 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. Notwithstanding this exception, a report must be filed for:**

**(i) Conditions under paragraph (a)(1) of this section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; and**

**(ii) Any condition under paragraph (a)(10) of this section.**

**[Issued by Amdt. 191-6, 53 FR 24942, July 1, 1988 with Amdt. 191-6 Correction, 53 FR 26560, July 13, 1988; Amdt. 191-14, 63 FR 37500, July 13, 1998; Amdt. 191-24, 81 FR 91872, Dec. 19, 2016; Amdt. 191-26, Oct. 1, 2019; Amdt. 191-30, 86 FR 63294 Nov. 15, 2021]**

## GUIDE MATERIAL

*This guide material is under review following Amdt. 191-26.*

(a) For the purpose of Safety-Related Condition Reports, "in-service facilities" are those that are pressurized with gas, regardless of flow conditions. Facilities that are not "in-service" are completely depressurized and isolated from all pressurized facilities by valves or physical separation.

(b) Section 192.605 requires operators to have procedures enabling O&M personnel to recognize conditions that potentially may be safety-related conditions. See Guide Material Appendix G-191-3 for charts useful in determining if reports must be filed.

(c) See 4.4 of the guide material under §192.605 for actions to consider in response to safety-related conditions. See guide material under §192.617 for failure investigation, when applicable.

(d) If the MAOP plus the build-up allowed for operation of pressure-limiting or control devices on a transmission line is exceeded, the *Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011* ("Act")(Section 23(b)) states that the operator is to notify the Secretary of Transportation, and appropriate state agencies if the pipeline is subject to state regulations, on or before the fifth calendar day of the exceedance. PHMSA-OPS issued Advisory Bulletin ADB-2012-11 (77 FR 75699, Dec. 21, 2012;

reference Guide Material Appendix G-192-1, Section 2) to advise owners and operators of gas transmission pipeline facilities of new reporting requirements in the Act. The Act states that exceedance is to be reported even if the condition is corrected within the reporting timeframe. The Advisory Bulletin requests operators to submit information comparable to that required for a safety-related condition (see Guide Material Appendix G-191-4). The operator should note that the reporting requirement for an exceedance is calendar days, as opposed to the safety-related conditions requirement of working days that does not include Saturdays, Sundays, or federal holidays.

# §191.25

## Filing safety-related condition reports.

*[Effective Date: 07/01/2020]*

**(a) Each report of a safety-related condition under §191.23(a)(1) through (9) must be filed (received by the Associate Administrator) in writing within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of an 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. Reporting methods and report requirements are described in paragraph (c) of this section.**

**(b) Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in § 191.23(a)(10) for a gas transmission pipeline must be filed (received by the Associate Administrator) in writing within 5 calendar days of the exceedance using the reporting methods and report requirements described in paragraph (c) of this section.**

**(c) Reports must be filed by email to *InformationResourcesManager@dot.gov* or by facsimile to (202) 366-7128. For a report made pursuant to § 191.23(a)(1) through (9), the report must be headed "Safety-Related Condition Report." For a report made pursuant to § 191.23 (a)(10) the report must be headed "Maximum Allowable Operating Pressure Exceedances." All reports must provide the following information:**

**(1) Name, principal address, and operator identification number (OPID) of the 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.**

**[Issued by Amdt. 191-6, 53 FR 24942, July 1, 1988 with Amdt. 191-6 Correction, 53 FR 26560, July 13, 1988 and Amdt. 191-6 Correction, 53 FR 29800, Aug. 8, 1988; Amdt. 191-7, 54 FR 32342, Aug. 7, 1989; Amdt. 191-8, 54 FR 40878, Oct. 4, 1989; Amdt. 191-10, 61 FR 18512, Apr. 26, 1996; Amdt. 191-23, 80 FR 12762, Mar. 11, 2015, Amdt. 191-26, Oct. 1, 2019]**

## GUIDE MATERIAL

*This guide material is under review following Amdt. 191-26.*

(a) The preamble to Amendment 191-7 ("Interpretation and Statement of Policy Regarding Discovery of Safety-Related Conditions by Smart Pigs and Instructions to Personnel") states:

> "Discovery of a potentially reportable condition occurs when an operator's representative has adequate information from which to conclude the probable existence of a reportable condition. An operator would have adequate information for each anomaly that is physically examined. Absent physical examination, discovery may occur after the data are calibrated if the "adequate information" test is met. However, the adequacy of the information that pig data provide about anomalous conditions is contingent on a concurrent indication from a number of factors from which an operator could conclude the probable existence of a reportable condition. Among these are the sophistication of the pig being used, the reliability of the data, the accuracy of data interpretation, and any other factors known by the operator relative to the condition of the pipeline."

(b) See Guide Material Appendix G-191-4 for a form useful for reporting a safety-related condition.

(c) Additional state requirements may exist for intrastate facilities.

# §191.29

## National Pipeline Mapping System.

*[Effective Date: 10/01/15]*

**(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.**

**(c) This section does not apply to gathering pipelines.**

**[Issued by Amdt. 191-23, 80 FR 12762, Mar. 11, 2015; Amdt. 191-30, 86 FR 63294 Nov. 15, 2021]**

## GUIDE MATERIAL

Operators will need to reflect changes due to service conversion or product change (see §191.22(c)(1)(vi)) on subsequent National Pipeline Mapping System submissions.

# PART 192

# TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

**Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et. seq*., and 49 CFR 1.97.**
**Source: Originally 35 FR 13248, Aug. 19, 1970; currently Amdt. 192-124, 83 FR 58694, Nov. 20, 2018.**

## SUBPART A
## GENERAL

## §192.1
### What is the scope of this part?

*[Effective Date: 03/05/07]*

**(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**

***Entirely replaced onshore transmission pipeline segments*** **means, for the purposes of §§192.179 and 192.634, where 2 or more miles, in the aggregate, of onshore transmission pipeline have been replaced within any 5 contiguous miles of pipeline within any 24-month period.**

***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.**

***Moderate consequence areas*** **means*:***

**(1)** ***An onshore area that is within a potential impact circle, as defined in § 192.903, containing either:***

- **(i) Five or more buildings intended for human occupancy; or**

- **(ii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's** ***Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1*** **(see:** *https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf***), and that does not meet the definition of high consequence area, as defined in § 192.903.**

**(2) The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either 5 or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either 5 or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, or any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.**

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

***Notification of potential rupture*** **means the notification to, or observation by, an operator of indicia identified in §192.635 of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline.**

***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 $^{o}$F (38 $^{o}$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.**

***Rupture-mitigation valve (RMV)*** **means an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture.**

***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.**

***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.**

***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 9083, Apr. 10, 1973; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-67, 56 FR 63764, Dec. 5, 1991; Amdt. 192-72, 59 FR 17275, Apr. 12, 1994 with Amdt. 192-72 Ext., 59 FR 49896, Sept. 30, 1994, Amdt. 192-72 Ext. Correction, 59 FR 52863, Oct. 19, 1994 and Amdt. 192-72 Ext., 60 FR 7133, Feb. 7, 1995; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-81, 62 FR 61692, Nov. 19, 1997 with Amdt. 192-81 Confirmation, 63 FR 12659, Mar. 16, 1998; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-89, 65 FR 54440, Sept. 8, 2000; RIN 2137-AD43, 68 FR 11748, Mar. 12, 2003; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69 FR 54591, Sept. 9, 2004 and Amdt. 192-94 DFR [Correction], 70 FR 3147, Jan. 21, 2005; Amdt. 192-98, 69 FR 48400, Aug. 10, 2004; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; Amdt. 192-112, 74 FR 63310, Dec. 3, 2009; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015; Amdt 192-122, 81 FR 91872, Dec. 19, 2016; Amdt 192-124, 83 FR 58694, Nov. 20, 2018; Amdt 192-125, Oct. 1, 2019; Amdt. 192-129, 86 FR 63294, Nov. 15, 2021; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

## GUIDE MATERIAL

*This guide material is currently under review following Amdt. 192-125.*

### Glossary of Commonly Used Terms

(For Glossary of Commonly Used Abbreviations, see Table 192.3i below.)

*Abandoned pipeline* is a pipeline that is physically separated from its source of gas and is no longer maintained under Part 192.

*Abandonment* is the process of abandoning a pipeline.

*Adhesive joint* is a joint made in thermosetting plastic piping by the use of an adhesive substance that forms a bond between the mating surfaces without dissolving either one of them.

*Ambient temperature* is the temperature of the surrounding medium, usually used to refer to the temperature of the air in which a structure is situated or a device operates. See also *Ground Temperature* and *Temperature*.

*Bell-welded pipe* is furnace-welded pipe that has a longitudinal butt joint that is forge-welded by the mechanical pressure developed in drawing the furnace-heated skelp through a cone-shaped die. The die, commonly known as a "welding bell," serves as a combined forming and welding die. This type of pipe is produced in individual lengths from cut-length skelp. Typical specifications: ASTM A53, API Spec 5L. See also *Furnace-butt-welded pipe* and *Pipe manufacturing processes*.

*Bottle* is a gastight structure that is (1) completely fabricated by the manufacturer from pipe with integral drawn, forged, or spun end closures; and (2) tested in the manufacturer's plant. See also *Bottle-type holder*.

*Bottle-type holder* is any bottle or group of interconnected bottles installed in one location, and used for the sole purpose of storing gas. See also *Bottle*.

*Carbon steel*. By common custom, steel is considered to be carbon steel where (i) no minimum content is specified or required for aluminum, boron, chromium, cobalt, columbium, molybdenum, nickel, titanium, tungsten, vanadium, zirconium, or any other element added to obtain a desired alloying effect; (ii) the specified minimum content for copper does not exceed 0.40 percent; or (iii) the specified maximum content does not exceed 1.65 percent for manganese, 0.60 percent for silicon or 0.60 percent for copper.

All carbon steels may contain small quantities of unspecified residual elements unavoidably retained from raw materials. These elements (copper, nickel, molybdenum, chromium, etc.) are considered incidental and are not normally determined or reported.

*Cast iron*. The unqualified term cast iron applies to gray-cast iron that is a cast ferrous material in which a major part of the carbon content occurs as free carbon in the form of flakes interspersed through the metal.

*Christmas tree* is an assembly consisting of valves, fittings, pressure gauges, and connecting components used at ground level atop a wellhead to control the flow of gas into or out of the well.

*Cold-expanded pipe* is seamless or welded pipe that is formed and then, expanded in the pipe mill while cold, so that the circumference is permanently increased by at least 0.50 percent.

*Compressor station* is a pipeline facility installed for the purpose of mechanically increasing the gas pressure on a pipeline system or for reducing back-pressure on upstream gas facilities to enhance flow. Other facilities that might be located at the same site but not actually part of the compressor station include measurement, treatment, processing, and pressure control.

*Continuous-welded pipe* is furnace-welded pipe which has a longitudinal butt joint that is forge-welded by the mechanical pressure developed in rolling the hot-formed skelp through a set of round pass welding rolls. It is produced in continuous lengths from coiled skelp and subsequently cut into individual lengths. Typical specifications (see §192.7): ASTM A53, API Spec 5L. See also *Furnace-butt-welded pipe* and *Pipe manufacturing processes*.

*Control piping* is pipe, valves, and fittings used to interconnect air, gas, or hydraulically operated control apparatus.

*Copper Tube Size (CTS)* is an alphanumeric sizing convention for copper or plastic components comprised of the letters CTS preceded by a dimensionless number (e.g., ½ CTS). The CTS "size" is indirectly related to the nominal outside diameter used in the design of copper tubing (§192.125) or plastic tubing (§192.121). In all cases, the actual nominal outside diameter, using the CTS sizing convention, will measure 1/8 inch greater than the nominal CTS size. For example, ½ CTS tubing has an actual nominal outside diameter of 0.625 inches (0.500 + 0.125 inch).

*Cross bore* is an intersection of an existing underground utility or underground structure by a second utility. This typically occurs when the use of trenchless technology results in direct contact between utilities or underground structures that compromises the integrity of either.

*Curb valve* is a type of service-line valve installed for the purpose of shutting off gas supply. It is typically installed below grade at or near the property line.

*Deactivation (Inactivation)* is the process of making the pipeline inactive.

*District regulator* station or district pressure regulating station is a pressure regulating station that controls pressure to a high- or low-pressure distribution main. It does not include pressure regulation whose sole function is to control pressure to a manifold serving multiple customers.

*Double submerged-arc-welded pipe* is a pipe having longitudinal or spiral butt joints. The joints are produced by at least two passes, including at least one each on the inside and on the outside of the pipe. Coalescence is produced by heating with an electric arc or arcs between the bare metal electrode or electrodes and the work. The welding is shielded by a blanket or granular, fusible material on the work. Pressure is not used and filler metal for the inside and outside welds is obtained from the electrode or electrodes. Typical specifications (see §192.7): ASTM A381, API Spec 5L. See also *Pipe manufacturing processes*.

*Dry gas* is gas above its dew point and without condensed liquids.

*Ductile iron* (sometimes called nodular iron) is a cast ferrous material in which the free graphite present is in a spheroidal form rather than a flake form. The desirable properties of ductile iron are achieved by means of chemistry and a ferritizing heat treatment of the castings.

*Electric-flash-welded pipe* is pipe having a longitudinal butt joint wherein coalescence is produced, simultaneously over the entire area of abutting surfaces, by the heat obtained from resistance to the flow of electric current between the two surfaces, and by the application of pressure after heating is substantially completed. Flashing and upsetting are accompanied by the expulsion of metal from the joint. Typical specification (see §192.7): API Spec 5L. See also *Pipe manufacturing processes*.

*Electric-fusion-welded pipe* is pipe having a longitudinal butt joint wherein coalescence is produced in the preformed tube by manual or automatic electric-arc welding. The weld may be single or double and may be made with or without the use of filler metal. Typical specifications (see §192.7 and Guide Material Appendix G-192-1A): ASTM A134, ASTM A139: Single or double weld is permitted with or without the use of filler metal. ASTM A671, ASTM A672, ASTM A691, and API Spec 5L: Requires both inside and outside welds and use of filler metal.

Spiral-welded pipe is also made by the electric-fusion-welded process with either a butt joint, a lap joint, or a lock-seam joint. Typical specifications (see §192.7 and Guide Material Appendix G-192-1A): ASTM A134, ASTM A139, and API Spec 5L: Butt joint. ASTM A211: Butt joint, lap joint, or lock-seam joint. See also *Pipe manufacturing processes*.

*Electric-resistance-welded (ERW)* pipe is pipe, which has a longitudinal butt joint wherein coalescence, is produced by the application of pressure and by the heat obtained from the resistance of the pipe to the flow of an electric current in a circuit of which the pipe is a part. It is produced in individual lengths or in continuous lengths from coiled skelp and subsequently cut into individual lengths. Typical specifications (see §192.7 and Guide Material Appendix G-192-1A): ASTM A53, ASTM A135, and API Spec 5L. See also *Pipe manufacturing processes*.

*Electrolyte* is a chemical substance containing ions that migrate in an electric field. Electrolytes can play a role in external corrosion or internal corrosion of metallic pipelines. For external corrosion, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged piping system, including the moisture and other chemicals contained therein. For internal corrosion, electrolyte refers to the chemicals contained in water inside the pipeline, including solutions of salts, acids, and bases.

*Electrolytic contact (also known as an electrolytic couple or electrolytic short)* is ionic contact between two metallic structures via an electrolyte.

*Excess Flow Valve (EFV)* is a device installed in a gas pipeline to automatically restrict or shut off the gas flow through the line when the flow exceeds a predetermined limit.

*Excess Flow Valve-Bypass (EFVB)* is an EFV that is designed to limit the flow of gas upon closure to a small, predetermined level. EFVBs reset automatically once the line downstream is made gastight and pressure is equalized across the valve.

*Excess Flow Valve-Non-Bypass (EFVNB)* is an EFV that is designed to stop the flow of gas upon closure. EFVNBs must be manually reset.

*Furnace-butt-welded pipe*. There are two such types of pipe defined in this glossary: *Bell-welded pipe* and *Continuous-welded pipe*. See also *Pipe manufacturing processes*.

*Furnace-lap-welded pipe* is pipe that has a longitudinal lap joint that is produced by the forge welding process. In this process, coalescence is produced by heating a preformed tube to welding temperature and then passing it over a mandrel. The mandrel is located between the two welding rolls that compress and weld the overlapping edges. Typical specification: API Spec 5L. The manufacture of this type of pipe was discontinued, and the process was deleted from API Spec 5L in 1962 (see §192.7 and Guide Material Appendix G-192-1A). See also *Pipe manufacturing processes*.

*Gas control* is a person or persons who acquire and maintain data to remotely monitor and direct the flow of gas to meet design and contractual obligations, and to assist in detecting pipeline emergencies and initiating response. See related definitions of *Control room* and *Controller* in §192.3.

*Ground temperature* is the temperature of the earth at pipe depth. See also *Ambient temperature* and *Temperature*.

*Heat-fusion joint* is a joint made in thermoplastic piping by heating the parts sufficiently to permit fusion of the materials when the parts are pressed together.

*Holiday* is a coating imperfection that exposes the pipe surface to the environment.

*Holiday detection* is testing of a coating for holidays using an instrument that applies a voltage between the external surface of the coating and the pipe.

*Hoop stress* is the stress in a pipe wall, acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe, produced by the pressure of the fluid in the pipe. In this Guide, hoop stress in steel pipe is calculated by the formula:

$$S_h = \frac{PD}{2t}$$

Where:

$S_h$ = Hoop stress, psi
$P$ = Internal pressure, psig
$D$ = Nominal outside diameter of pipe, inches
$t$ = Nominal wall thickness, inches

See also *Maximum allowable hoop stress*.

*Hot taps* are connections made to transmission lines, mains, or other facilities while they are in operation. The connecting and tapping is done while the facility is under gas pressure.

*Hydrostatic Design Basis (HDB)* is one of a series of established stress values specified in ASTM D2837, "Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products," for a plastic compound, obtained by categorizing the long-term hydrostatic strength as determined in accordance with ASTM D2837.

*Inactive pipeline* is a pipeline that is being maintained under Part 192 but is not presently being used to transport gas. See guide material under §192.727.

*Instrument piping* is pipe, valves, and fittings used to connect instruments to main piping, to other instruments and apparatus, or to measuring equipment.

*Iron*. See *Cast iron*, *Ductile iron*, and *Malleable iron*.

*Iron Pipe Size (IPS)* is an alphanumeric sizing convention for cast iron or plastic components comprised of the letters IPS followed by a dimensionless number (e.g., IPS 2). It was originally related to cast iron piping, but has been adopted by the plastic pipe specifications (i.e., ASTM D2513 - see §192.7) as a plastic pipe sizing convention. IPS is not used for steel piping.

*Jeeping* is a method of *Holiday detection*.

*Joint.* See *Length*.

*Lateral line (transmission)*. See guide material under §192.625.

*Leak surveys* are systematic inspections made for the purpose of finding leaks in a gas piping system. The types of inspections commonly made are described in Guide Material Appendix G-192-11 "Gas Leakage Control Guidelines for Natural Gas Systems" and Guide Material Appendix G-192-11A "Gas Leakage Control Guidelines for Petroleum Gas Systems."

*Length* is a piece of pipe as delivered from the mill. Each piece is called a length regardless of its actual longitudinal dimension. While this is sometimes called a "joint," the term "length" is preferred.

*Light surface oxide* is a non-damaging form of corrosion.

*Long-term hydrostatic strength (LTHS)* of plastic pipe is the estimated hoop stress, in psi, that would result in a failure of the pipe if the pipe were subjected to 100,000 hours of hydrostatic pressure.

*Lower Explosive Limit (LEL)* is the lower limit of flammability for a gas expressed as a percent, by volume, of gas in air.

*Malleable iron* is a mixture of iron and carbon, including small amounts of silicon, manganese, phosphorous, and sulfur which, after being cast, is converted structurally by heat treatment into primarily a matrix of ferrite containing nodules of tempered carbon.

*Maximum allowable hoop stress* is the maximum hoop stress permitted for the design of a piping system. It depends upon the material used, the class location of the pipe, and the operating conditions. See also *Hoop stress*.

*Maximum allowable test pressure is the maximum internal fluid pressure permitted for testing, for the materials and class location involved.*

*Metallic short* is direct metallic contact between two metallic structures.

*Meters*. See *Meter set assembly*.

*Meter set assembly* is that exposed portion of the service line extending from the service line riser valve to the connection of the customer's fuel line, including the meter, and (if present) the regulator and relief vent line. In the absence of a service line riser valve, the meter set assembly starts at the first exposed fitting. The meter set assembly does not include the customer's buried or exposed fuel line. If the operator's service line continues past the meter and connects to the customer's fuel line at a location some distance downstream of the meter, the meter set assembly ends at the meter outlet valve (if present) or at the first exposed fitting (e.g., coupling or union) downstream of the meter.

*Monitoring regulator* is a pressure regulator, set in series with another pressure regulator, for the purpose of providing automatic overpressure protection in the event of a malfunction of the primary regulator.

*Nodular iron*. See *Ductile iron*.

*Nominal outside diameter (D)* is the outside diameter, in inches, as listed in Table 192.105i for nominal pipe size (NPS) 12 and less, and is the same as the nominal pipe size for greater than NPS 12. It is used in the design formula for steel pipe in §192.105 and the calculation for hoop stress. Steel, plastic in IPS and NPS sizes, and some types of cast iron pipe have the same nominal outside diameters. Matching diameters are used when replacing cast iron or steel pipe with plastic pipe. Table 192.121ii lists the outside diameters used in the design formula for copper or matching plastic pipe.

*Nominal Pipe Size (NPS)* is an alphanumeric sizing convention for steel and plastic components comprised of the letters NPS followed by a dimensionless number (e.g., NPS 2). NPS and IPS have the same nominal outside diameter for a given size. The NPS/IPS "number" originally represented the actual measured inside diameter of the piping, but this is not always true. The nominal outside diameter (D) used in the design formulas for NPS piping can be obtained from Table 192.105i or the various product specifications.

*Nominal wall thickness (t)* is the wall thickness, in inches, computed by, or used in, the design formula for steel pipe in §192.105. Pipe may be ordered to this computed wall thickness without adding an allowance to compensate for the under-thickness tolerances permitted in approved specifications.

*Operating stress* is the stress in a pipe or structural member under normal operating conditions.

*Otherwise changed* is a substantial physical alteration of a pipeline facility as opposed to a repair or restoration (Amdt. 192-102). The original alignment or functionality of the pipeline facility is modified by the alteration. Examples of a substantial physical alteration include the following.

(a) Addition of a pig launcher or receiver to a pipeline.
(b) Addition of a mainline block valve.
(c) Relocation of a pipeline.
(d) Connection of a lateral.

*Overpressure protection* is the use of a device or equipment installed for the purpose of preventing pressure in a pipe system or other facility from exceeding a predetermined limit. See also *Pressure limiting station*, *Pressure regulating station*, and *Pressure relief station*.

*Parallel encroachment* pertains to that portion of the route of a transmission line or main that lies within, runs in a generally parallel direction to, and does not necessarily cross, the rights-of-way of a road, street, highway, or railroad.

*Pipe*. See *Bell-welded pipe*, *Cold-expanded pipe*, *Continuous-welded pipe*, *Control piping*, *Double-submerged-arc-welded pipe*, *Electric-flash-welded pipe*, *Electric-fusion-welded pipe*, *Electric- resistance-welded pipe*, *Furnace-butt-welded pipe*, *Furnace-lap-welded pipe*, *Instrument piping*, *Length*, *Pipe-container*, *Pipe manufacturing processes*, *Pipe-type holder*, *Sample piping*, and *Seamless pipe*.

*Pipe-container* is a gastight structure assembled from pipe and end closures. See also *Pipe-type holder*.

*Pipe manufacturing processes. A reference is ASME I00396 "History of Line Pipe Manufacturing in North America." Types and names of welded joints are used herein as defined in the American Welding Society (AWS) Publication A3.0 "Standard Welding Terms and Definitions" except for the following terms which are defined in this glossary.*

*Bell-welded pipe*
*Continuous-welded pipe*
*Double-submerged-arc-welded pipe*
*Electric-flash-welded pipe*
*Electric-fusion-welded pipe*
*Electric-resistance-welded pipe*
*Furnace-butt-welded pipe*

*Furnace-lap-welded pipe*
*Seamless pipe*

*Pipe-type holder* is any pipe-container or group of interconnected pipe-containers installed at one location for the sole purpose of storing gas. See also *Pipe-container*.

*Plastic* (noun) is a material that contains one or more organic polymeric substances of high molecular weight as an essential ingredient, is solid in its finished state, and can be shaped by flow at some stage of its manufacture or processing into finished articles. The two general types of plastic referred to in this Guide are thermoplastic and thermosetting. See also *Thermoplastic* and *Thermosetting plastic*.

*Plastic pipe joints*. See *Adhesive joint*, *Heat-fusion joint*, and *Solvent cement joint*.

*Pressure* (expressed in pounds per square inch above atmospheric pressure, i.e., gauge pressure (abbreviation: psig), unless otherwise stated). See also *Maximum allowable test pressure*, *Overpressure protection*, *Pressure limiting station*, *Pressure regulating station*, *Pressure relief station*, and *Standup pressure test*.

*Pressure limiting station* consists of apparatus which, under abnormal conditions, will act to reduce, restrict, or shut off the supply of gas flowing into a transmission line, main, holder, pressure vessel, or compressor station piping in order to prevent the gas pressure from exceeding a predetermined limit. While normal pressure conditions prevail, the pressure limiting station may exercise some degree of control of the flow of gas or may remain in the wide-open position. Included in the station are any enclosures and ventilating equipment, and any piping and auxiliary equipment, such as valves, control instruments, or control lines.

*Pressure regulating station* consists of apparatus installed for the purpose of automatically reducing and regulating the gas pressure in the downstream transmission line, main, holder, pressure vessel, or compressor station piping to which it is connected. Included in the station are any enclosures and ventilating equipment, and any piping and auxiliary equipment, such as valves, control instruments, or control lines.

*Pressure relief station* consists of apparatus installed to vent gas from a transmission line, main, holder, pressure vessel, or compressor station piping in order to prevent the gas pressure from exceeding a predetermined limit. The gas may be vented into the atmosphere or into a lower pressure gas system capable of safely receiving the gas being discharged. Included in the station are any enclosures and ventilating equipment, and any piping and auxiliary equipment, such as valves, control instruments, or control lines.

*Private rights-of-way* are those that are not located on roads, streets, or highways used by the public, or on railroad rights-of-way.

*Proprietary items* are items made by a company having the exclusive right of manufacture.

*Public place* is a place that is generally open to all persons in a community as opposed to being restricted to specific persons. A public place includes churches, schools, and commercial property, as well as any publicly owned right-of-way or property that is frequented by people.

*Public road*, *street*, or *highway* is a general term denoting a public way for the purpose of vehicular travel, including the entire area within its right-of-way.

*Reference datum is a known and constant surface which is used to describe the location of points on the earth. The most common reference datum sets used in North America are NAD27, NAD83, and WGS84.*

*Regulators*. See *Pressure limiting station*, *Pressure regulating station*, and *Pressure relief station*.

*Right-of-way* is a general term denoting land, property, or interest therein, usually in a strip, acquired for or devoted to specific purpose such as a highway or pipeline.

*Sample piping* is pipe, valves, and fittings used for the collection of samples of gas or other fluids.

*Seamless pipe* is a wrought tubular product made without a welded seam. It is manufactured by hot working steel or, if necessary, by subsequently cold finishing the hot-worked tubular product to produce the desired shape, dimensions, and properties. See also *Pipe manufacturing processes*.

*Secondary stress* is stress created in the pipe wall by loads other than internal fluid pressure. Examples are backfill loads, traffic loads, beam action in a span and loads at supports and at connections to the pipe.

*Service-line valve* is a valve located in a service line and meets the requirements of §192.363. A service-line valve may be a curb valve, or other valve, located upstream of the:

(a) service regulator,
(b) meter and any meter bypass, where there is no service regulator, or
(c) connection to customer piping if there is no meter.

*Slack loop* is extra pipe length installed to counter the effects of pipe expansion and contraction.

*Solvent cement joint* is a joint made in PVC piping by using solvent cement to join the piping components.

*Standup pressure test* is a test to demonstrate that a pipe or piping system does not leak as evidenced by the lack of a drop in pressure over a specified period of time after the source of pressure has been isolated.

*Steel* is an iron-base alloy, malleable in some temperature range as initially cast, containing manganese, carbon, and often other alloying elements. See also *Carbon steel*.

*Stress* is the resultant internal force that resists change in the size or shape of a body acted on by external forces. See also *Hoop stress*, *Maximum allowable hoop stress*, *Operating stress*, *Secondary stress*, *Tensile strength*, and *Yield strength*.

*Stress corrosion cracking* of metallic pipe is the formation of cracks, typically in a colony or cluster, as a result of the interaction of tensile stress, a corrosive environment, and a susceptible material.

*Subject Matter Experts (SMEs)* are persons knowledgeable about design, construction, operations, maintenance, or characteristics of a pipeline system. Designation as an SME does not necessarily require specialized education or advanced qualifications. Some SMEs may possess such expertise, but detailed knowledge of the pipeline system gained by working with it over time can also make someone an SME. SMEs may be employees, consultants, contractors, or any suitable combination of these.

*Subsurface safety valve (SSSV)* is a downhole device installed in the production (flow) string of a well to prevent uncontrolled flow from a well in the event of an emergency. An SSSV may be surface-controlled or subsurface-controlled.

*Temperature* (expressed in degrees Fahrenheit (ºF) unless otherwise stated). See also *Ambient temperature* and *Ground temperature*.

*Tensile strength* is the highest unit tensile stress (referred to the original cross section) that a material can sustain before failure (psi)

*Thermoplastic* is a plastic that is capable of being repeatedly softened by increase of temperature and hardened by decrease of temperature. Examples of thermoplastic materials include polyethylene (PE), polyamide (PA or nylon), and polyvinyl chloride (PVC).

*Thermosetting plastic* is a plastic that is capable of being changed into a substantially infusible or insoluble product when cured under the application of heat or by chemical means. Examples of thermosetting plastic materials include:

(a) Epoxy as used in epoxy fiberglass pipe, "Red Thread®" pipe, and fiber-reinforced pipe (FRP); and
(b) Unsaturated polyester as used in fiberglass composites for steel pipe repair sleeves, and cured-in-place (CIP).

*Thickness*. See *Nominal wall thickness*.

*Valve*. See *Curb valve* and *Service-line valve*.

*Vault* is an underground structure which may be entered, and which is designed to contain piping and piping components, such as valves or pressure regulators.

*Wellhead* is a structure installed at the surface of a gas well to provide the structural and pressure-containing interface between the subsurface casing strings and the surface facilities including the Christmas tree.

*Yield strength* is the strength at which a material exhibits a specified limiting permanent set, or produces a specified total elongation under load. The specified limiting set or elongation is usually expressed as a percentage of gage length, and its values are specified in the various material specifications acceptable under this Guide.

# §192.9

## What requirements apply to gathering lines?

*[Effective Date: 7/01/2020]*

**(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, 192.285(e), 192.493, 192.506, 192.607, 192.619(e), 192.624, 192.710, 192.712, 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, 192.285(e), 192.493, 192.506, 192.607, 192.619(e), 192.624, 192.710, 192.712, 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. Compliance with §§ 192.67, 192.127, 192.179(e), 192.179(f), 192.205, 192.227(c), 192.285(e), 192.506, 192.634, and 192.636 is not required.**

**(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except the requirements in § 192.493;**

**(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(a), (b), and (c);**

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

**(e) *Type C lines*. The requirements for Type C gathering lines are as follows.**

**(1) An operator of a Type C onshore gathering line with an outside diameter greater than or equal to 8.625 inches must comply with the following requirements:**

**(i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B through G and J of this part applicable to transmission lines. Compliance with §192.67, 192.127, 192.179(e), 192.179(f), 192.205,192.227(c), 192.285(e), 192.506, 192.634, and 192.636 is not required;**

**(ii) If the pipelines is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except for §192.493;**

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

**(iv) Develop and implement procedures for emergency plans in accordance with §192.615;**

**(v) Develop and implement a written public awareness program in accordance with §192.616;**

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

**(vii) 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).**

**(2) An operator of a Type C onshore gathering line with an outside diameter greater than 12.75 inches must comply with the requirements in paragraph (e)(1) of this section and the following:**

**(i) If the pipeline contains plastic pipe, the operator must comply with all applicable requirements of this part for plastic pipe or components. This does not include pipe and components made of composite materials that incorporate plastic in the design; and**

**(ii) Establish the MAOP of the pipeline under §192.619(a) or (c) and maintain records used to establish the MAOP for the life of the pipeline.**

**(f) *Exceptions.* (1) Compliance with paragraphs (e)(1)(ii),(v),(vi), and (vii) and (e)(2)(i) and (ii) of this section is not required for pipeline segments that are 16 inches or less in outside diameter if one of the following criteria are met:**

**(i) *Method 1*. The segment is not located within a potential impact circle containing a building intended for human occupancy or other impacted site. The potential impact circle must be calculated as specified in §192.903, except that a factor of 0.73 must be used instead of 0.69. The MAOP used in this calculation must be determined and documented in accordance with paragraph (e)(2)(ii) of this section.**

**(ii) *Method 2.* The segment is not located within a class location unit (see §192.5) containing a building intended for human occupancy or other impacted site.**

**(2) Paragraph (e)(1)(i) of this section is not applicable to pipeline segments 40 feet or shorter in length that are replaced, relocated, or changed on a pipeline existing on or before May 16, 2022.**

**(3) For purposes of this section, the term "building intended for human occupancy or other impacted site" means any of the following:**

**(i) Any building that may be occupied by humans, including homes, office buildings factories, outside recreation areas, plant facilities, etc;**

**(ii) 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); or**

**(iii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.**

**(g) *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 Type A or Type B regulated onshore gathering pipeline 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 pipeline listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:**

| Requirement | Compliance deadline |
|---|---|
| (i) Control corrosion according to requirements for transmission lines in subpart I of this part. | April 15, 2009 |
| (ii) Carry out a damage prevention program under §192.614. | October 15, 2007 |

| Requirement | Compliance deadline |
|---|---|
| **(iii) Establish MAOP under §192.619.** | **October 15, 2007** |
| **(iv) Install and maintain line markers under §192.707.** | **April 15, 2008** |
| **(v) Establish a public education program under §192.616** | **April 15, 2008** |
| **(vi) 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 pipeline to become a Type A or Type B regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the pipeline becomes a regulated onshore gathering pipeline to comply with this section.**

**(4) If a Type C gathering pipeline existing on or before May 16, 2022, was not previously subject to this part, an operator must comply with the applicable requirements of this section, except for paragraph (h) of this section, on or before:**

**(i) May 16, 2023; or**

**(ii) An alternative deadline approved by PHMSA. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with §192.18 and must include a description of the affected facilities an operating environment, the proposed alternative deadline for each affected requirement, the proposed alternative deadline for each affected requirement, the justification for each alternative compliance deadline, and actions the operator will take to ensure the safety of affected facilities.**

**(5) If, after May 16, 2022, a change in class location, an increase in dwelling density, or an increase in MAOP causes a pipeline to become a Type C gathering pipeline, or causes a Type C gathering pipeline to become subject to additional Type C requirements (*see* paragraph (f) of this section), the operator has 1 year after the pipeline becomes subject to the additional requirements to comply with this section.**

**(h) *Composite materials*. Pipe and components made with composite materials not otherwise authorized for use under this part may be used on Type C gathering pipelines if the following requirements are met:**

**(1) Steel and plastic pipe and components must meet the installation, construction, initial inspection, and initial testing requirements in subpart B through G and J of this part applicable to transmission lines.**

**(2) Operators must notify PHMSA in accordance with §192.18 at least 90 days prior to installing new or replacement pipe or components made of composite materials otherwise not authorized for use under this part in a Type C gathering pipeline. The notifications required by this section must include a detailed description of the pipeline facilities in which pipe or components made of composite materials would be used, including:**

**(i) The beginning and end points (stationing by footage and mileage with latitude and longitude coordinates) of the pipeline segment containing composite pipeline material and the counties and States in which it is located;**

**(ii) A general description of the right-of-way including high consequence areas, as defined in §192.905;**

**(iii) Relevant pipeline design and construction information including the year of installation, the specific composite material, the diameter, wall thickness, and any manufacturing and construction specifications for the pipeline;**

**(iv) Relevant operating information, including MAOP, leak and failure history, and the most recent pressure test (identification of the actual pipe tested, minimum and maximum test pressure, duration of test, any leaks and any test logs and charts) or assessment results;**

**(v) An explanation of the circumstances that the operator believes make the use of composite pipeline material appropriate and how the design, construction, operations, and maintenance will mitigate safety and environmental risks;**

**(vi) An explanation of procedures and tests that will be conducted periodically over the life of the composite pipeline material to document that its strength is being maintained;**

**(vii) Operations and maintenance procedures that will be applied to the alternative materials. These include procedures that will be used to evaluate and remediate anomalies and how the operator will determine safe operating pressures for composite pipe when defects are found;**

**(viii) An explanation of how the use of composite pipeline material would be in the public interest; and**

**(ix) A certification signed by a vice president (or equivalent or higher officer) of the operator's company that operation of the applicant's pipeline using composite pipeline material would be consistent with pipeline safety.**

**(3) Repairs or replacements using materials authorized under this part do not require notification under this section.**

**[Amdt. 192-72, 59 FR 17275, Apr. 12, 1994 with Amdt. 192-72 Ext., 59 FR 49896, Sept. 30, 1994, Amdt. 192-72 Ext. Correction, 59 FR 52863, Oct. 19, 1994 and Amdt. 192-72 Ext., 60 FR 7133, Feb. 7, 1995; Amdt. 192-95, Correction & Petition for Reconsideration, 69 FR 18228, Apr. 6, 2004; Amdt. 192-102, 71 FR 13289, Mar. 15, 2006; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015; Amdt 192-124, 83 FR 58694, Nov. 20, 2018; Amdt 192-125, Oct. 1, 2019; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

## GUIDE MATERIAL

*This guide material is under review following Amendment 192-124 and 192-125.*

(a) See §192.1 for gathering lines excluded from the provisions of Part 192. Also, see the "Glossary of Commonly Used Terms" under §192.3 for definition of "*Otherwise changed*."
(b) See Guide Material Appendix G-192-22

# §192.10

## Outer continental shelf pipelines.

*[Effective Date: 03/08/05]*

**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.**

**[Issued by Amdt. 192-81, 62 FR 61692, Nov. 19, 1997 with Amdt. 192-81 Confirmation, 63 FR 12659, Mar. 16, 1998; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005]**

## GUIDE MATERIAL

No guide material necessary.

# §192.11

## Petroleum gas systems.

*[Effective Date: 08/06/15]*

**(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 59 (incorporated by reference, *see* §192.7), NFPA 58 and NFPA 59 prevail.**

**[Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-119, 80 FR 168, Jan. 5, 2015 with Amdt. 192-119 Correction, 80 FR 46847, Aug. 6, 2015]**

## GUIDE MATERIAL

### 1 GENERAL

*1.1 Introduction.*

Personnel involved in the design, construction, operation, and maintenance of petroleum gas systems should be thoroughly familiar with the applicable provisions of the Federal Regulations and referenced NFPA Standards (see §192.7 for IBR).

Figure 192.11A depicts the standards applicable to petroleum gas plants that supplement natural gas systems, as described in §192.11(a).

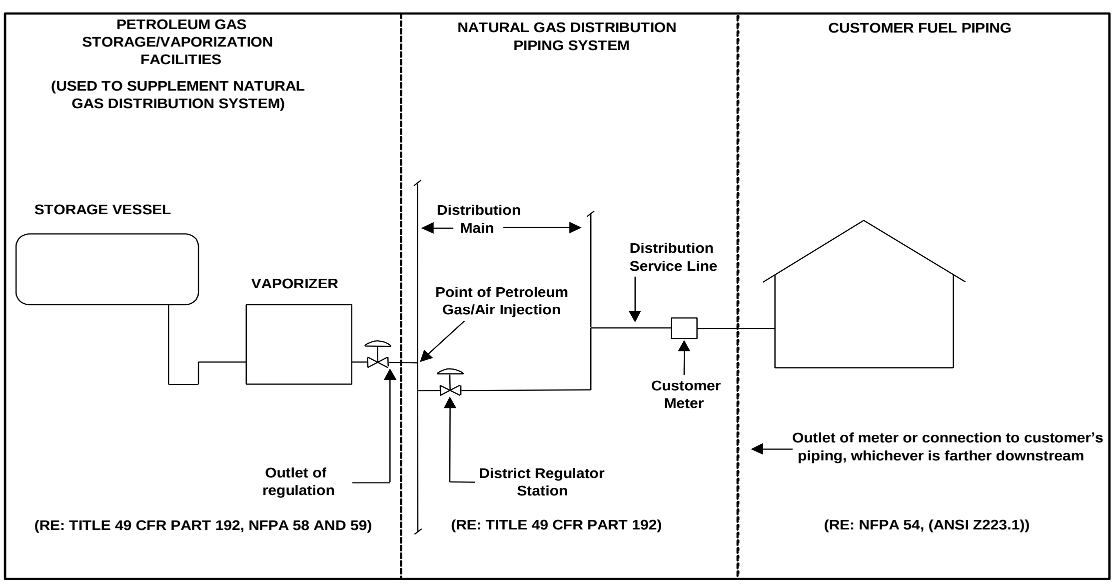


**FIGURE 192.11A**

Figure 192.11B depicts the standards applicable to pipeline systems for petroleum gas or petroleum gas/air mixtures, as described in §192.11(b).

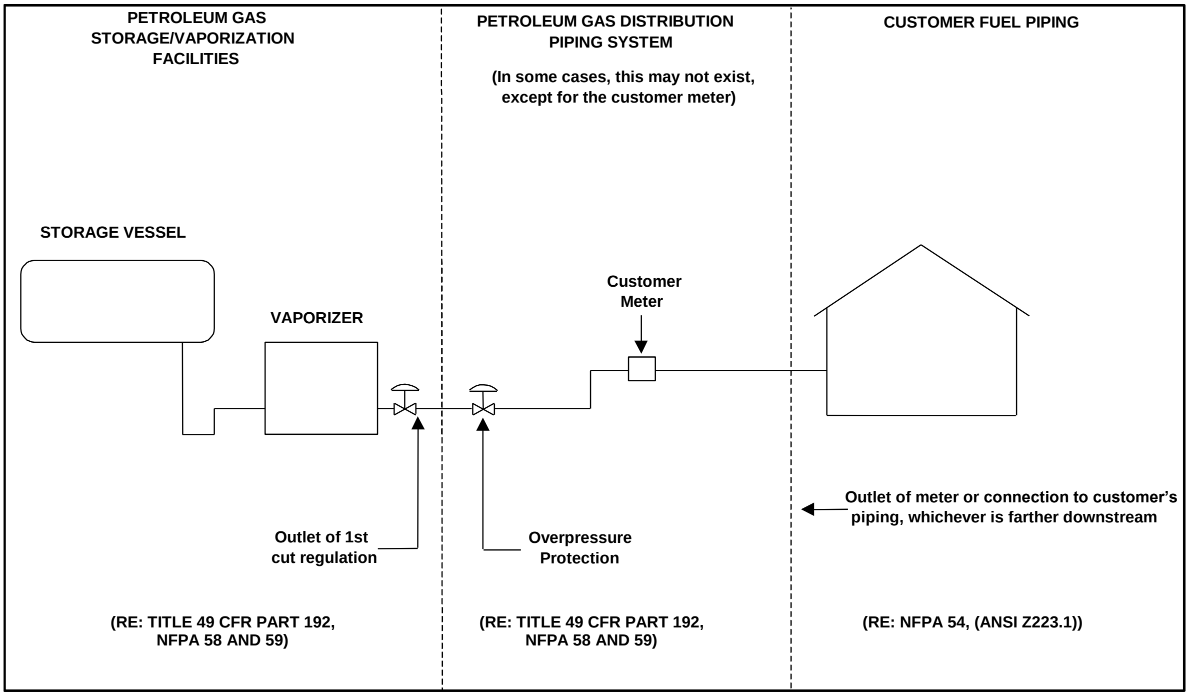


**FIGURE 192.11B**

1.2 *Application of referenced codes*.

(a) General. The referenced NFPA Standards are applicable unless otherwise superseded, in whole or in part, by local governmental agency codes, rules, or regulations having jurisdiction.

(b) Plant and storage facilities. These facilities include storage tanks and all piping and equipment to the outlet of the first pressure regulator. Utility plant facilities having a total water storage capacity greater than 4,000 gallons are covered by NFPA 59. All other plant and storage installations should comply with NFPA 58.

(c) Distribution piping. This includes the pipeline from the outlet of the first pressure regulator to:

(1) The outlet of the customer meter or the connection to the customer's piping, whichever is farther downstream; or

(2) The connection to the customer's piping if there is no customer meter.

(d) Customer piping. This includes all piping and facilities downstream of the distribution piping. These facilities are not included in the scope of 49 CFR 192. NFPA 54/ANSI Z223.1 (National Fuel Gas Code) referenced in Figures 192.11A and 192.11B is applicable unless otherwise superseded by the laws, regulations, or building codes of a local jurisdictional authority.

1.3 *Conflict between referenced codes.*

If the referenced NFPA Standards are silent or non-specific on a subject for which requirements exist in Part 192, then a conflict does not exist and operators should comply with Part 192 requirements.

1.4 *Reference*.

Operators of petroleum gas distribution and master meter systems may benefit from information provided in the "Guidance Manual for Operators of LP Gas Systems" and "Operator Qualification Guidance Manual for Operators of LP Gas Systems" available at https://www.phmsa.dot.gov/training/pipeline/guidance-manuals.

## 2 PERSONNEL SAFETY

(a) Operators should ensure that personnel who work with petroleum gases know the following.
  (1) Physical properties of these gases (e.g., heavier than air).
  (2) Safe work practices for activities associated with petroleum gases that include the following.
    (i) Handling.
    (ii) Distributing.
    (iii) Operation and maintenance.
(b) For certain operations and maintenance tasks performed on a petroleum gas system, personnel may need to be qualified in accordance with Subpart N.

## 3 USE OF PLASTIC PIPE

See guide material under §§192.121 and 192.123.

## 4 LEAKAGE CONTROL GUIDELINES

See Guide Material Appendix G-192-11A.

# §192.12

## Underground natural gas storage facilities.

*[Effective Date: 01/18/17]*

**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 nonmandatory 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]**

## GUIDE MATERIAL

*Note*: This guide material is based upon the adoption of an Interim Final Rule (81 FR 91860, December 19, 2016, effective January 18, 2017). PHMSA issued a Stay of Enforcement (82 FR 28224, June 20, 2017) to consider issues raised in comments received and to announce the suspension of enforcement citations for a period of one year after the Final Rule is published.

### 1 API RP 1170 AND API RP 1171 (See §192.7 for IBR)

Guidance provided in API RP 1170 for solution-mined salt caverns and API RP 1171 for depleted hydrocarbon reservoirs and aquifer reservoirs used for the underground storage of natural gas is represented as "recommended practices." However, §192.12(f) requires the operator to follow the general program recommendations of API RP 1170 or API RP 1171, as applicable, unless the operator justifies in its written program or procedural manual why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

### 2 REFERENCES

(a) National standards and the sections referencing them in API RP 1170 and API RP 1171 are as follows.

**TABLE 192.12-1**

| National Standard | API RP 1170 | API RP 1171 |
|---|---|---|
| API Bulletin 5A2, *Bulletin on Thread Compounds for Casing, Tubing, and Line Pipe* | * | |
| API Bulletin E3, *Well Abandonment and Inactive Well Practices* | | 6.7.1 |
| API Guidance Document HF1, *Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines* | | 6.5.3 |
| API Guidance Document HF2, *Water Management Associated with Hydraulic Fracturing* | | 6.5.3 |
| API Guidance Document HF3, *Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing* | | 6.5.3 |
| API RP 5A3, *Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements* | 8.4.2.6 | |
| API RP 5A5, *Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe* | * | |
| API RP 5B1, *Gauging and Inspection of Casing, Tubing and Line Pipe Threads* | * | |
| API RP 5C1, *Recommended Practice for Care and Use of Casing and Tubing* | 8.4.2.5 | |
| API RP 10D-2, *Recommended Practice for Centralizer Placement and Stop-collar Testing* | | 6.4.5 |
| API RP 10F, *Recommended Practice for Performance Testing of Cementing Float Equipment* | 2, 7.6.1 | |
| **TABLE 192.12-1 (Continued)** | | |

| National Standard | API RP 1170 | API RP 1171 |
|---|---|---|
| API RP 13D, *Rheology and Hydraulics of Oil-well Drilling Fluids* | * | |
| API RP 14B, *Design, Installation, Repair and Operation of Subsurface Safety Valve Systems* | | 6.2.5 |
| API RP 14E, *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems* | | 6.3.5 |
| API RP 49, *Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide* | | 6.8.1 |
| API RP 51R, *Environmental Protection for Onshore Oil and Gas Production Operations and Leases* | | 5.5.1, 6.8.1 |
| API RP 53, *Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells* | * | 11.5.2 |
| API RP 54, *Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations* | | 6.8.1, 11.5.2, 11.6.2 |
| API RP 76, *Contractor Safety Management for Oil and Gas Drilling and Production Operations* | | 5.5.1, 6.8.1 |
| API RP 1114, *Recommended Practice for the Design of Solution-Mined Underground Storage Facilities* | * | |
| API RP 1115, *Design and Operation of Solution-mined Salt Caverns Used for Liquid Hydrocarbon Storage* | * | |
| API Specification 5CT, *Specification for Casing and Tubing* | * | |
| API Specification 5DP, *Specification for Drill Pipe* | * | |
| API Specification 5L, *Specification for Line Pipe* | * | |
| API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment* | * | 6.2.1 |
| API Specification 6D, *Specification for Pipeline Valves* | * | |
| API Specification 10A, *Specification for Cements and Materials for Well Cementing* | 2, 7.6.1 | 6.4.2, 6.7.2 |
| API Specification 14A, *Specification for Subsurface Safety Valve Equipment* | | 6.2.5 |
| API Standard 65-2, *Isolating Potential Flow Zones during Well Construction* | | 6.4.5 |
| API Standard 1104, *Welding of Pipelines and Related Facilities* | * | |
| API Technical Report 5C3, *Calculating Performance Properties of Pipe Used as Casing or Tubing* | 2, 8.4.2.3 | |
| API Technical Report 10TR1, *Cement Sheath Evaluation* | | 6.4.6 |
| API Technical Report 10TR3, *Technical Report on Temperatures for API Cement Operating Thickening Time Tests* | * | |
| API Technical Report 10TR4, *Selection of Centralizers for Primary Cementing Operations* | * | 6.4.5 |
| ASTM C150/C150M, *Standard Specification for Portland Cement* | | 6.4.2, 6.7.2 |
| ASTM D3740, *Standard Practice for Minimum Requirements for Agencies Engaged in Testing and/or Inspection of Soil and Rock as Used in Engineering Design and Construction* | 5.4.2.1 | |
| ASTM D3967, *Standard Test Method for Splitting Tensile Strength of Intact Rock Core Specimens* | 2, 5.4.2.4 | |
| ASTM D4543, *Standard Practices for Preparing Rock Core as Cylindrical Test Specimens and Verifying Conformance to Dimensional and Shape Tolerances* | 2, 5.4.2.3 | |
| ASTM D4645, *Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method* | 2, 5.4.4 | |

be expected. The following criteria should be used for the selection of inspection sites.

(a) Corrosion surveys (inadequately protected segments, poor coating, stray currents, and interference).
(b) Pipeline component locations.
(c) Locations subject to mechanical damage.
(d) Foreign pipeline crossings.
(e) Locations subject to damage due to chemicals, such as acid.
(f) Segments subject to coating deterioration due to soil stresses and internal or external temperature extremes.
(g) Population density.

**4 REGULATORY DOCUMENTS**

For pipelines being converted under this section, the operator should review it's procedural manual for operations, maintenance, and emergencies and its public education program for compliance to Part 192 prior to placing the converted line into a natural gas service.

## §192.15

### Rules of regulatory construction.

*[Effective Date: 11/12/70]*

**(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.**

**GUIDE MATERIAL**

*No guide material necessary.*

## §192.16

### Customer notification.

*[Effective Date: 05/04/98]*

**(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.**

**[Issued by Amdt. 192-74, 60 FR 41821, Aug. 14, 1995 with Amdt. 192-74 Correction, 60 FR 43028, Aug.18, 1995 and Amdt. 192-74A, 60 FR 63450, Dec. 11, 1995; Amdt. 192-84, 63 FR 7721, Feb. 17, 1998 with Amdt. 192-84 Confirmation, 63 FR 38757, July 20, 1998 and Amdt. 192-84 Correction, 63 FR 38758, July 20, 1998]**

**GUIDE MATERIAL**

*No guide material necessary.*

## §192.18

## How to notify PHMSA.

*[Effective Date: 07/01/2020]*

**(a) An operator must provide any notification required by this part by –(1) Sending the notification by electronic mail to *InformationResourcesManager@dot.gov*; or (2) 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.,**

**(b) An operator must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate applicable pipeline segment is regulated by the State.**

**(c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, 192.9, 192.179, 192.506, 192.607, § 192.619, 192.624, 192.632, 192.634, 192.636, 192.710, 192.712, 192.745, 192.921 or 192.937 a notification for use of a different integrity assessment method, analytical method, sampling approach, or technique ( *e.g.,* "other technology" or "alternative equivalent technology") than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator**

**that PHMSA objects to the proposal, or that PHMSA requires additional time and/or information to conduct its review.**

**[Issued by Amdt. 192-125, Oct. 1, 2019; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-125.*

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# SUBPART B
# MATERIALS

## §192.51
## Scope.

*[Effective Date: 11/12/70]*

**This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.**

### GUIDE MATERIAL

### 1 GENERAL

Operators designing and installing gathering lines that are not regulated at the time of installation should be aware of the materials of construction in case the pipeline becomes regulated in the future and whether the materials used were manufactured under a listed specification.
Examples of non-listed materials include the following.
(a) Polyethylene manufactured according to ASTM F2619 and API 15LE.
(b) Spoolable composite materials manufactured in accordance with API 15S.
(c) Mechanical interference fit joint and other non-qualified joints and joining systems.

### 2 MATERIALS

Repairs or replacements on regulated segments of gathering lines must be performed using materials manufactured to a listed specification (§192.53).

### 3 SPECIAL PERMIT (WAIVER)

*Note:* A "special permit" was previously referred to as a "waiver" by PHMSA-OPS. State terminology may differ (e.g., waiver, variance).

If a segment of previously non-regulated gathering line becomes regulated, PHMSA-OPS or the state agency with jurisdiction may consider special permit (waiver) requests under §190.341 to implement alternative measures to provide an equivalent or greater level of safety, provided that the terms and conditions of the special permit are met.

## §192.53
## General.

*[Effective Date: 11/12/70]*

**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.**

## GUIDE MATERIAL

### 1 FRACTURE TOUGHNESS REQUIREMENTS

(a) Seam-welded steel pipe, 20 inches and larger in diameter and with SMYS of 52,000 psi or higher to be installed in transmission lines and Type A gathering lines to operate at 40% or more of SMYS and at operating pipe temperature less than 60 $^{o}$F, should exhibit sufficient notch ductility at the operating pipe temperature. Compliance with either the Charpy impact or drop weight test criteria specified in SR5 or SR6 of API Spec 5L (see §192.7 for IBR) is sufficient evidence of such ductility when impact tests are made at or below the design pipe temperature.

(b) For special installations (e.g., compressor station piping, small replacement sections), the notch ductility should be determined by appropriate criteria, which may include those specified in SR5 or SR6 of API Spec 5L.

(c) Notch ductility tests are not necessary on pipe for small special installations (e.g., new highway crossings and extensions of compressor station headers) where pipe to be installed (i) is on hand from earlier purchases to specifications at least equal to those applicable at the time of the original installation, or (ii) is a short portion of a larger order that exhibited adequate notch ductility.

### 2 SOUR GAS COMPATIBILITY

(a) See guide material under §192.475 for internal corrosion considerations.

(b) NACE MR0175 contains guidelines for selecting materials for valves used in sour gas service. The use of controlled hardness techniques and the use of alternate materials, as described in NACE MR0175, may be effective for other components in controlling sulfide stress cracking. The use of controlled hardness techniques should not be considered a solution to other problems involving $H_2S$.

## §192.55
## Steel pipe.

*[Effective Date: 08/06/15]*

**(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).**

**[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-12, 38 FR 4760, Feb. 22, 1973; Amdt. 192-51, 51 FR 15333, Apr. 23, 1986; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-119, 80 FR 168, Jan. 5, 2015 with Amdt. 192-119 Correction, 80 FR 46847, Aug. 6, 2015]**

**GUIDE MATERIAL**

Listed specifications are shown in Section I of Appendix B. The user is cautioned that there may be more recent editions of some of these specifications than those approved and listed in Section I of Appendix B.

## §192.57

## (Removed and reserved.)

*[Effective Date: 03/08/89]*

## §192.59

## Plastic pipe.

*[Effective Date: 01/22/19]*

**(a) New plastic pipe is qualified for use under this part if —**

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

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

**(3) It is free of visible defects**

**(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 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 materials 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.**

**[Amdt. 192-19, 40 FR 10471, Mar. 6, 1975; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

## GUIDE MATERIAL

*This guide material is under review following Amendment 192-124.*

### 1 GENERAL

Each operator should establish that new or used pipe complies with the requirements of the applicable ASTM piping specification (referenced in §192.7) for the type of plastic pipe, such as ASTM D2513-09a for polyethylene (PE), ASTM D2513-99 for other thermoplastics, or ASTM D2517 for thermosetting plastics by one of the following methods.

(a) Inspection and testing by an accredited laboratory with written certification.
(b) Inspection and testing by the user.
(c) Written certification from the manufacturer at the time of purchase. Included as part of this certification should be copies of the production quality control records referenced by lot and shift numbers.

### 2 WEATHERING STATEMENT FOR PLASTIC PIPE

(a) The resistance of plastic pipe to outdoor exposure can vary greatly. The manufacturer of the plastic pipe should be required to supply a written statement of the period of time the product can be stored outside without loss of properties that qualify it for buried gas piping application. ASTM pipe specifications include UV resistance requirements for outdoor storage stability. The operator should ensure that this exposure time is not exceeded. Examples: ASTM D2513-09a specifies that black PE pipe or black PE pipe with yellow stripes can be stored outdoors, unprotected from UV radiation, for up to 10 years and that yellow PE pipe can be stored outdoors for up to 3 years.
*Note:* For aboveground installation, see (d) below.
(b) When storing outdoors, cumulative exposure periods should be considered. The Pipe Production Code marked on the pipe includes the date of manufacture. In general, most manufacturers store pipe outdoors prior to shipment, and allowance for this period should be made. Exposure time can be minimized by issuing from storage on a "first-in, first-out" rotation, with the date of manufacture used as a control. The pipe with the earliest date of manufacture should be issued first for installation.
(c) To limit UV exposure time and prevent degradation, plastic pipe may be stored indoors away from UV exposure or outdoors with a protective cover.
(d) For limitations and considerations on the use of plastic pipe temporarily installed above ground, see §192.321(g) and guide material under §192.321.

## §192.61
**(Removed and reserved.)**

*[Effective Date: 03/08/89]*

# §192.63

## Marking of materials.

*[Effective Date: 01/22/19]*

**(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.**

**(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.**

**(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.**

**[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-31, 43 FR 13880, Apr. 3, 1978 with Amdt. 192-31A, 43 FR 21462, May 18, 1978; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988 with Amdt. 192-61A, 54 FR 32641, Aug. 9, 1989; Amdt. 192 62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-76, 61 FR 26121, May 24, 1996 with Amdt. 192-76 Correction, 61 FR 36825, July 15, 1996; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

### GUIDE MATERIAL

*This guide material is under review following Amendment 192-124.*

(a) The manufacturer marks the pipe and fittings with the maximum temperature at which the pipe and fittings have been qualified for use. For example: PE 2406/PE 2708 CDC - The first letter following the 4-digit number designates the maximum temperature at which the piping material's hydrostatic design basis (HDB) has been established and, thus, the maximum temperature at which the pipe can be used. The second letter indicates the HDB for the piping material at that maximum temperature and the third letter is the categorized melt index (actual values are listed in ASTM D2513 - see §192.7 for IBR). The first letter designations from ASTM D2513 are as follows.

A=100 ºF
B=120 ºF
C=140 ºF
D=160 ºF
E=180 ºF

*Note:* The HDB expresses the long-term strength of a thermoplastic material in terms of a series of standard strength categories (e.g., 1600 psi, 1250 psi, 1000 psi) which have been established in accordance with ASTM D2837. Specific HDBs can be obtained from the manufacturer and from the Plastics Pipe Institute (PPI).

(b) Thermoplastic pipe manufactured prior to August 16, 1978 may not be marked with the appropriate code letters for elevated temperature operation. Operators who have installed such pipe should take proper precautions to ensure the pipe is used only within the actual temperature and stress limits for which it was tested and qualified. See §192.123(b)(2).

(c) Marking requirements for PE pipe manufactured after March 6, 2015 are described in ASTM D2513-09a. All other new installations of thermoplastic materials must meet the ASTM D2513-87 (see §192.7 for IBR) marking requirements (§192.63(a)).

## §192.65
## Transportation of pipe.

*[Effective Date: 10/01/15]*

**(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. 192-12, 38 FR 4760, Feb. 22, 1973; Amdt. 192-17, 40 FR 6345, Feb. 11, 1975 with Amdt. 192-17 Correction, 40 FR 24361, June 6, 1975; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]**

### GUIDE MATERIAL

*No guide material necessary*

## §192.67
## Records: Material properties

*[Effective Date: 07/01/20]*

**(a) For steel transmission pipelines installed after [July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with §§ 192.53 and 192.55. Records must include tests, inspections and attributes required**

**by the manufacturing specifications applicable at the time the pipe was manufactured or installed.**

**(b) For steel transmission pipelines installed on or before July 1, 2020], if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with §§ 192.53 and 192.55, operators must retain such records for the life of the pipeline.**

**(c) For steel transmission pipeline segments installed on or before July 1, 2020], if an operator does not have records necessary to establish the MAOP of the pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.**

**[Amdt 192-125, Oct. 1, 2019]**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-125.*

## §192.69

## Storage and handling of plastic pipe and associated components

*[Effective Date: 01/22/19]*

**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.**

**[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

**GUIDE MATERIAL**

*No guide material available at present.*

Regulations. Current documents incorporated by reference that were listed in Appendix A prior to Amendment 192-94, published June 14, 2004, are now found in §192.7.

(b) If the edition of the document under which the component was manufactured was neither previously listed nor currently listed in §192.7, and was not previously listed in Appendix A, then requirements under §192.144(b) should be reviewed to determine if the metallic component is qualified for use under Part 192. Gas quality and composition should be considered for components used in gathering systems.

*Note*: See guide material under §192.51.

## §192.145
## Valves.

*[Effective Date: 01/22/19]*

**(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.**

**(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.**

**[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-22, 41 FR 13589, Mar. 31, 1976; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

## GUIDE MATERIAL

*This guide material is under review following Amendment 192-124.*

### 1 FLANGED CAST IRON VALVES IN STEEL PIPELINES

Consideration should be given to the effect of secondary stresses (e.g., those resulting from earth movement, expansion and contraction, or other external forces) which could affect the structural integrity of flanged cast iron valves in steel pipelines. The operator should consider the following.

(a) Adequate support, for the both the cast iron valve and the adjacent steel piping.
(b) If compression couplings are used, the couplings should be designed to resist axial stresses from the adjacent steel piping.
(c) Other means.

For joining considerations, see 1, 2, 3, and 6 of the guide material under §192.273.

### 2 EQUIVALENT STANDARDS FOR STEEL VALVES

*2.1 Equivalent standards*.

Valve standards API Spec 6A, API Std 600, ASME B16.33, ASME B16.34, and ASME B16.38 provide an equivalent performance level to API Spec 6D (see §192.7 for IBR) for gas application purposes.

*2.2 Valves not listed in* API Spec 6D.

Although all valve sizes (e.g., those smaller than 2 inches) are not listed in API Spec 6D, manufacturers may design, build, and test non-listed sizes in accordance with all applicable requirements of API Spec 6D and, thereby, meet the equivalency criteria. However, application of the API monogram to valve sizes not listed in the API Specification is not permitted.

### 3 PRESSURE-TEMPERATURE RATING

Any valve which cannot comply to the API Spec 6D standard pressure-temperature rating because of material(s) which require a reduced maximum temperature limit should be provided with markings on the nameplate showing the maximum pressure rating at that temperature and with the pressure rating at 100 $^{o}$F.

### 4 GAS COMPOSITION

If the gas to be transported could contain constituents such as carbon dioxide, hydrogen sulfide, free water, brine, oxygen, or liquid hydrocarbons, the selection of valves should include evaluation for material compatibility. See additional guide material under §192.475.

### 5 PLASTIC VALVES

ASTM D2513 (see §192.7 for IBR) requires that all plastic valves meet the requirements of ASME B16.40, "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems." The manufacturing test requirements outlined in §192.145(b) for plastic valves are part of the testing requirements outlined in ASME B16.40.

### 6 COMPRESSOR STATION PIPING COMPONENTS

Steel valves with balls or plugs constructed from cast iron, malleable iron, or ductile iron may be installed in compressor station piping.

# §192.147

## Flanges and flange accessories.

*[Effective Date: 03/06/15]*

**(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5 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.**

**[Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]**

### GUIDE MATERIAL

### 1 FLANGES

*1.1 Flange types.*

(a) The dimensions and drilling for all line or end flanges should conform to one of the following standards.

ASME B16.1, ASME B16.5, ASME B16.36, ASME B16.47, ASME B16.48, AWWA C207, or MSS SP-44 as listed in either §192.7 or Guide Material Appendix G-192-1.

Flanges cast or forged integral with pipe, fittings or valves in sizes and for the maximum service rating covered by the standards listed above may be used subject to the facing, bolting and gasketing requirements of this paragraph and 1.2, 2.1 and 2.2 below.

(b) Threaded companion flanges that comply with either ASME B16.1 or ASME B16.5 (see §192.7 for IBR for both), in sizes and for maximum service ratings covered by these standards, may be used.

(c) Lapped flanges in sizes and pressure standards established by ASME B16.5 may be used.

(d) Slip-on welding flanges in sizes and pressure standards established in ASME B16.5 may be used. Slip-on flanges of rectangular section may be substituted for hubbed slip-on flanges provided the thickness is increased as required to produce equivalent strength as determined by calculations made in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII (see §192.7).

(e) Welding neck flanges in sizes and pressure standards established in ASME B16.5, ASME B16.47, and MSS SP-44 (see §192.7 for IBR) may be used. The bore of the flanges should correspond to the inside diameter of the pipe used. For acceptable welding end treatment, see Guide Material Appendix G-192-5, Figure 192.235B.

(f) Flanges made of ductile iron should conform to material and dimensional standards listed in §192.145(a) and should be subject to all service restrictions as outlined for valves in that paragraph. The bolting requirements for ductile-iron flanges should be the same as for carbon and low-alloy steel flanges as listed in 2.1 below.

*1.2 Flange facings.*

(a) Cast iron, ductile iron, and steel flanges should have contact faces finished in accordance with MSS SP-6, Finishes for Contact Faces of Pipe Flanges of Connecting-End Flanges of Valves and Fittings.

(b) Class 25 and Class 125 cast iron integral or threaded companion flanges may be used with a full-face gasket or with a flat ring gasket extending to the inner edge of the bolt holes. When using a full-face gasket, the bolting may be of alloy steel (ASTM A193). When using a ring gasket, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307

Grade B.

(c) When bolting together two Class 250 integral or threaded companion cast iron flanges, having 1/16 inch raised faces, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B.

(d) Class 150 steel flanges may be bolted to Class 125 cast iron flanges. When such construction is used, the 1/16 inch raised face on the steel flange should be removed. When bolting such flanges together, using a flat ring gasket extending to the inner edge of the bolt holes, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B. When bolting such flanges together using a full-face gasket, the bolting may be alloy steel (ASTM A193).

(e) Class 300 steel flanges may be bolted to Class 250 cast iron flanges. Where such construction is used, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B. It is recommended that the raised face on the steel flange be removed. When this is done, bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B.

(f) Forged steel welding neck flanges have an outside diameter and drilling the same as ASME B16.1, but with modified flange thicknesses, hub dimensions, and special facing details, may be used to bolt against flat-faced cast iron flanges, and may operate at the pressure-temperature ratings given in ASME B16.1 Class 125 Cast Iron Pipe Flanges provided:
   (1) The minimum flange thickness, *T*, of the steel flange is not less than that specified for size 6 inch and larger.
   (2) Flanges are used with nonmetallic full-face gaskets extending to the periphery of the flange.
   (3) The design joint has been proven by test to be suitable for the ratings.

## 2 FLANGE ACCESSORIES

*2.1 Bolting*.

(a) For all flange joints other than described under 1.2(c), (d), (e) and (f), the bolting should be made of alloy steel conforming to ASTM A193, A320 or A354, or of heat-treated carbon steel conforming to ASTM A449. However, bolting for American National Standard Class 250 and 300 flanges to be used at temperatures between minus 20 ºF and plus 450 ºF may be made to ASTM A307, Grade B.

(b) Alloy steel bolting material conforming to ASTM A193 or ASTM A354 should be used for insulating flanges if such bolting is made ⅛ inch undersized.

(c) The materials used for nuts should conform to ASTM A194 and A307. A307 nuts may be used only with A307 bolting.

(d) All carbon and alloy steel bolts, stud bolts, and their nuts should be threaded in accordance with the following thread series and dimension class as required by ASME B1.1.
   (1) *Carbon Steel* - All carbon steel bolts and stud bolts should have coarse threads, Class 2A dimensions and their nuts, Class 2B dimensions.
   (2) *Alloy Steel* - All alloy steel bolts and stud bolts of 1 inch and smaller nominal diameters should be of the coarse thread series; nominal diameters 1⅛ inch and larger should be of the 8 thread series. Bolts and stud bolts should have a Class 2A dimension, and their nuts should have a Class 2B dimension.

(e) Bolts should have American National Standard regular square heads or heavy hexagonal heads and should have American National Standard heavy hexagonal nuts conforming to the dimensions of ASME B18.2.1 and B18.2.2.

(f) Nuts cut from bar stock in such a manner that the axis will be parallel to the direction of rolling of the bar may be used in all sizes for joints in which one or both flanges are cast iron, and for joints with steel flanges where the pressure does not exceed 250 psig. Such nuts should not be used for joints in which both flanges are steel and the pressure exceeds 250 psig except that, for nut sizes ½ inch and smaller, these limitations do not apply.

(g) For all flange joints, the bolts or stud bolts used should extend completely through the nuts.

*2.2 Gaskets*.

(a) Material for gaskets should be capable of withstanding the maximum pressure and maintaining its physical and chemical properties at any temperature to which it might reasonably be subjected in service.

(b) Gaskets used under pressure and at temperatures above 250 ºF should be of noncombustible material. Metallic gaskets should not be used with Class 150 standard or lower-rated flanges.

(c) Full-face gaskets should be used with all bronze flanges, and may be used with Class 25 or Class 125 cast iron flanges. Flat ring gaskets with outside diameter extending to the inside of the bolt holes may be used with cast iron flanges, with raised face steel flanges, or with lapped steel flanges.

(d) In order to secure higher unit compression on the gasket, metallic gaskets of a width less than the full male face of the flange may be used with raised face, lapped, or large male and female facings. The width of the gasket for small male and female or for tongue and groove joints should be equal to the width of the male face or tongue.

(e) Rings for ring joints should be of dimensions established in ASME B16.20. The material for these rings should be suitable for the service conditions encountered and should be softer than the flanges.

*2.3 Insulating kits.*

(a) Insulating kits are available to provide electrical isolation at flanged connections. Insulating kits typically contain a gasket, washers, and sleeves for the bolts.

(b) Insulating kits should be specified to be compatible with both the gas stream and the external environment (e.g., temperature, pressure, gas quality or composition, moisture).

(c) Assembly.

(1) Carefully inspect the insulating kit components for rough edges, cracks, delaminations, or other defects that could contribute to crushing, cracking, or loss of seal under load.

(2) Ensure proper flange alignment and follow the manufacturer's assembly instructions, including torque values that may vary from non-insulating flange assemblies.

(3) Prior to coating or painting flanged connections, verify that desired insulating properties have been attained.

(4) Coating or painting materials should be nonconductive.

(d) Post assembly.

(1) Where possible, include the assembled insulating flange in pressure testing or perform an instrumented leak test prior to coating or painting.

(2) If the assembly is to be buried, consider providing a test station with test leads and bonding wires for future test capability. See §§192.469 and 192.471.

(3) Consider providing for ground fault, lightning protection, or temporary bonding. See §192.467.

## 3 FLANGE INSTALLATION AND MAINTENANCE

Proper installation and maintenance of flanged joints are critical for maintaining safe operation of pipeline facilities.

*3.1 Flange preparation.*

(a) The sealing surfaces of the flanges should be clean and smooth.

(b) To seal properly, the sealing faces should be installed parallel to each other.

*3.2 Bolting methods.*

Methods for tightening flange bolts may include the use of torque wrenches or the use of hydraulic stud tensioners.

(a) Bolt torque values.

(1) The proper bolt torque values are based on gasket material, flange size, flange type, flange rating, bolt size, bolt material, and thread lubricant. When available, the gasket manufacturer's recommended torque values should be followed.

(2) The minimum torque value represents the amount of force required to provide proper compression of the gasket to prevent leakage.

(3) The maximum torque value represents a torque limit to prevent gasket crushing, bolt yielding, flange deformation, or flange cracking.

(4) Thread lubrication significantly influences the amount of torque actually applied to the flange assembly. All flange bolts should be lubricated, and lubrication can be accomplished by using pre-coated bolts or by the field application of thread lubricants.

(b) Bolt torque procedure.
Bolt torque should be applied evenly across the flange and is normally applied in several steps. Bolt torque should be applied using manual or hydraulic torque wrenches. The following method provides an example of applying torque. The number of steps may vary based on recommendations of the gasket manufacturer and operator requirements. Except for the final step, use a star or crisscross pattern to tighten the bolts.
(1) Install and hand tighten all bolts and nuts.
(2) Tighten all bolts to 30% of the final torque value.
(3) Tighten all bolts to 60% of the final torque value.
(4) Tighten all bolts to 100% of the final torque value.
(5) Follow a circular pattern and ensure that all bolts are tightened to 100% of the final torque value.

(c) Hydraulic tensioning.
Hydraulic tensioning involves stretching the bolt to achieve a desired elongation as the nut is tightened onto the flange bolt. Advantages of hydraulic tensioning include the elimination of friction factor errors and more uniform gasket loading. The disadvantages of hydraulic tensioning include the need for longer studs, specialized equipment, and additional workspace.

## §192.149
## Standard fittings.

*[Effective Date: 01/22/18]*

**(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.**

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

### GUIDE MATERIAL

*This guide material is under review following Amendment 192-124.*

(a) Steel butt-welding fittings should comply with either ASME B16.9 or MSS SP-75 and should have pressure and temperature ratings based on stresses for pipe of the same or equivalent material.

(b) Steel induction bends should comply with ASME B16.49 and should have pressure and temperature ratings based on stresses for pipe of the same or equivalent material.

(c) Threaded fittings should comply with ASME B16.3, ASME B16.4, ASME B16.11, ASME B16.14, ASME B16.15, ASTM A733, MSS SP-83, or equivalent as appropriate.

(d) Socket welding fittings should comply with ASME B16.11, MSS SP-79, or MSS SP-83 or equivalent as appropriate.

**[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

# §192.150

## Passage of internal inspection devices.

*[Effective Date: 07/01/2020]*

**(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 in accordance with NACE SP0102, section 7 (incorporated by reference, *see* §192.7).**

**(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;**

**(8) Gathering lines; and**

**(9) 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 and 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.**

**[Issued by Amdt. 192-72, 59 FR 17275, April 12, 1994 with Amdt. 192-72 Ext., 59 FR 49896, Sept. 30, 1994, Amdt. 192-72 Ext. Correction, 59 FR 52863, Oct. 19, 1994 and Amdt. 192-72 Ext., 60 FR 7133, Feb. 7, 1995; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-97, 69 FR 36024, June 28, 2004, Amdt. 192-125, Oct. 1, 2019; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021]**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-125.*

**1 REFERENCES**
See Guide Material Appendix G-192-14 for design and construction considerations.

**2 GATHERING LINES**
Type A gathering lines are exempt from this requirement (§192.9(c)). No exemption exists for Type B gathering lines (§192.9(d).

## §192.151
## Tapping.

*[Effective Date: 07/13/98]*

**(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.**

**[Amdt. 192-85, 63 FR 37500, July 13, 1998]**

### GUIDE MATERIAL

**1 DESIGN**

*1.1 Proprietary fittings*.
- (a) General. When using proprietary hot tap fittings, the operator should ensure that the pressure-temperature rating, installation procedure and service restrictions have been established in accordance with sound engineering principles. The fittings should be used only in accordance with the manufacturer's recommendations.
- (b) Pressure-temperature ratings. Published catalog or engineering data supplied by a reputable manufacturer or designer is usually sufficient. When the rating cannot be so established, it should be established by test in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code, Section VIII (see §192.7).

*1.2 Other fittings.*
For design requirements for hot tap fittings fabricated by welding, see §192.153.

*1.3 Branch connection*.
For hot taps involving branch connections, see guide material under §192.155.

## 2 PRESSURE LIMITATIONS

Tapping equipment can have a maximum working pressure rating less than the fitting and less than the actual operating pressure of the pipeline being tapped. In that event, the operating pressure must be temporarily reduced during the tapping operation. If, in an emergency, a fitting is not qualified for the MAOP of the pipeline, the operating pressure must be lowered to the pressure rating of the fitting and must be maintained at or below this level until the fitting is removed.

## 3 SIZE LIMITATIONS

*3.1 Large-diameter taps*.

Large-diameter taps using mechanical fittings can reduce the remaining circumferential area below that required to withstand anticipated longitudinal forces due to pressure, bending, and thermal effects. The operator should anticipate and design for complete circumferential cracking. The operator should confirm that the longitudinal pullout resistance of the fitting is adequate, or provide appropriate restraint, such as a mechanical harness, strapping, or girth (fillet) end welds. For welds, see guide material under §192.713.

*3.2 Oversize taps*.

When an oversize tap (i.e., greater than 25% of the nominal diameter) into cast iron or ductile-iron pipe is made through a band-type fitting, it is common practice to use a full-encirclement gasket for leak containment in the event of a circumferential crack.

## 4 SEPARATION

To resist longitudinal cracks between taps, taps into cast iron or ductile-iron pipe should be separated longitudinally by at least the circumference of the pipe being tapped.

## 5 OTHER

See guide material under §192.627 for personnel qualifications, identification of pipe to be tapped, and suitability for tapping. See §192.627 for tapping pipelines under pressure.

# §192.153

## Components fabricated by welding.

*[Effective Date: 03/12/21]*

**(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 the ASME BPVC (Rules for Construction of Pressure Vessels as defined in either Section VIII, Division 1 or Section VIII, Division 2; incorporated by reference, see § 192.7), except for the following:**

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

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

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

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

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

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

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

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

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

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

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

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

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

**(5) The holder, connection pipe, and components must be leak tested after installation as required by Subpart J of this part.**

**[Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]**

**GUIDE MATERIAL**

For the definition of the bottle-type holder, see guide material under §§192.3 and 192.175.

## §192.179
## Transmission line valves.

*[Effective Date: 07/13/98]*

**(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.**

**(e) For onshore transmission pipeline segments with diameters greater than or equal to 6 inches that are constructed after March 31 2023, the operator must install rupture-mitigation valves (RMV) or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (g). All RMVs and alternative equivalent technologies installed pursuant to this paragraph must meet the requirements of §§192.634 and 192.636. Exempted from this paragraph's installation requirements are pipelines segments in Class 1, or Class 2 locations that have a potential impact radius (PIR), as defined in §192.903, of 150 feet or less. An operator may request an extension of the installation compliance deadlines requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that those installation**

**compliance deadlines would be economically, technically, or operationally, infeasible for a particular new pipeline.**

**(f) For entirely replaced onshore transmission pipeline segments, as defined in § 192.3, with diameters greater than or equal to 6 inches and that are installed after March 31 2023, the operator must install RMVs or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (g) of this section. All RMVs and alternative equivalent technologies installed pursuant to this paragraph must meet the requirements of §§192.634 and 192.636. The requirements of this paragraph apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. This paragraph's installation requirements do not apply to pipe segments in Class 1 or Class 2 locations that have a PIR, as defined in §192.903, that is less than or equal to 150 feet. An operator may request an extension of the installation compliance deadline requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in §192.18, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular pipeline replacement project.**

**(g) If an operator elects to use alternative equivalent technology in accordance with paragraphs (e) or (f) of this section, the operator must notify PHMSA in accordance with the procedures in §192.18. The operator must include a technical and safety evaluation in its notice to PHMSA. Valves that are installed as alternative equivalent technology must comply with §§ 192.634 and 192.636. An operator requesting use of manual valves as an alternative equivalent technology must also include within the notification submitted to PHMSA a demonstration that installation of an RMV as otherwise required would be economically, technically, or operationally infeasible. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, and use of such valve would not require a notification to PHMSA in accordance with § 192.18, but it must comply with § 192.636.**

**(h) The valve spacing requirements of paragraph (a) of this section do not apply to pipe replacements on a pipeline if the distance between each point on the pipeline and the nearest valve does not exceed:**

**(1) Four (4) miles in Class 4 locations, with a total spacing between valves no greater than 8 miles;**

**(2) Seven-and-a-half (7½) miles in Class 3 locations, with a total spacing between valves no greater than 15 miles; or**

**(3) Ten (10) miles in Class 1 or 2 locations, with a total spacing between valves no greater than 20 miles.**

**[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

## GUIDE MATERIAL

### 1 VALVE SPACING ON OFFSHORE-ONSHORE PIPELINES

(a) Where the distance between valves on a combined segment of a new offshore-onshore pipeline exceeds the valve spacing requirements for onshore pipelines, consideration should be given to the installation of a block valve at the nearest practical location to the land juncture of the pipeline segment.

(b) Sectionalizing block valves and blowdown valves associated with Type A and Type B gathering lines might need to be installed or relocated when any portion of a line is replaced, relocated, or otherwise changes.

## 2 BLOWDOWN RECOMMENDATIONS

*2.1 Blowdown duration and timing.*

(a) The operator should minimize blowdown time by properly sizing and placing blowdown discharges to:
   (1) Reduce the time gas is venting through a rupture and susceptible to ignition.
   (2) Reduce the duration of a gas fire, minimizing the impact on life and property.
   (3) Reduce the impact on flow capacity while the pipeline is out of service.

(b) The operator should consider the following when scheduling non-emergency blowdowns for pipeline maintenance or repairs.
   (1) Blow down during daylight hours to minimize noise emission impact on the public.
   (2) Blow down during favorable atmospheric conditions, so that vented gas is efficiently dispersed into the atmosphere and does not travel toward potential ignition sources or populated areas.
   (3) Provide advance notification to local residents, law enforcement, fire officials, and other pipeline operators in the area.
   (4) Coordinate blowdowns with the operator's personnel responsible for operation of the pipeline as well as customers whose service may be impacted by the blowdowns.

*2.2 Blowdown location.*

The following should be considered when locating blowdown discharges.

(a) Discharges should be located a sufficient distance away from buildings such that:
   (1) Should vented gas ignite, buildings will not be in danger of ignition or heat damage.
   (2) Noise emissions from blowdowns will have minimal impact on the public.
   (3) Methane emissions from blowdowns will have minimal public and environmental impact.

(b) Discharges should be located a sufficient distance away from overhead electric lines, and other potential ignition sources, so that the explosive gas / air concentrations of the dispersed vented gas do not come in contact with an ignition source.

*2.3 Blowdown emissions.*

Where practicable, operators should consider the following emission reducing actions during non-emergency blowdowns.

(a) Reduce methane emissions for environmental and economic reasons by:
   (1) Using existing compressor or regulator stations to pull down the pipeline pressure before blowdown.
   (2) Using a portable evacuation compressor to pull down the pipeline pressure by pumping the gas into another pipeline before blowdown.
   (3) Flaring the blowdown gas.

(b) Reduce entrained liquid emissions by:
   (1) Using blowdown separators.
   (2) Flaring the blowdown gas.

(c) Reduce noise emissions by using blowdown silencers, particularly in populated areas.

# §192.181

## Distribution line valves.

*[Effective Date: 11/12/70]*

**(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.**

## GUIDE MATERIAL

### 1 HIGH-PRESSURE DISTRIBUTION LINE VALVES (§192.181(a))

*1.1 Physical characteristics*.

The following physical characteristics should be considered when establishing high-pressure distribution system line valve locations.

(a) Size of area to be isolated.
(b) Topographic features, such as rivers, major highways and railroads.
(c) Number of valves necessary to isolate the area.

*1.2 Operating characteristics*.

The following operating characteristics should be considered when establishing locations for high-pressure distribution system line valves.

(a) Total number of customers and such customers as hospitals, schools, commercial, and industrial users that would be affected.
(b) Time required for available personnel to carry out isolation procedures.
(c) Time required for controlling the pressure in the isolated area by such means as venting and transferring gas to adjacent systems.
(d) Time required for available personnel to restore service to the customer.

### 2 REGULATOR STATION ISOLATION

Section 192.181(b) details the requirement for a valve on the inlet piping. When a distribution system is supplied by more than one regulator station, or when the system may reasonably be expected to create a significant backfeed, consideration should be given to isolating the stations from backfeed during an emergency. This may be accomplished by one of the following:

(a) Installing a valve on the station outlet piping.
(b) Utilizing valving in the distribution system to prevent a backfeed into the station.
(c) Developing a procedure to shut down all stations supplying the system.

## §192.183

## Vaults: Structural design requirements.

*[Effective Date: 07/13/98]*

§192.367.

## 2 SECONDARY STRESSES

*2.1 Transitions*.

The transition from plastic pipe to metal or to a more rigid section of plastic pipe should be supported by undisturbed or well-compacted soil, by bridging, or by sleeve encasement. In addition to providing adequate backfill and compaction around the transition area, the installation of protective sleeves or bridging should be considered to reduce excessive bending and shear stresses. These stresses have been known to cause premature brittle-like failures in some pre-1982 PE piping materials. For protective sleeves, see guide material under §192.367.

*2.2 Valve enclosures*.

Where curb boxes or other enclosures are used, they should not be supported by the plastic pipe and should not in any way impose secondary stresses on the plastic pipe.

*2.3 Coiled pipe*.

Valves installed in thermoplastic piping that has been coiled should be suitably restrained to prevent the rotation that may occur.

# §192.195

## Protection against accidental overpressuring.

*[Effective Date: 11/12/70]*

**(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.**

### GUIDE MATERIAL

## 1 GENERAL

*1.1 Inlet and outlet pressure rating considerations*.

Selection of inlet and outlet pressure ratings of control equipment, such as regulators and control valves, should include consideration of the following.

(a) The maximum inlet pressure at which the regulator will perform in accordance with the manufacturer's specifications.

(b) The maximum pressure to which the inlet may be subjected, under abnormal conditions, without causing damage to the regulator.

(c) The maximum outlet pressure at which the regulator will perform in accordance with the manufacturer's specifications.

(d) The maximum pressure to which the outlet may be subjected under abnormal conditions without causing damage to the internal parts of the regulator.

(e) The maximum outlet pressure which can be safely contained by the pressure-carrying components, such as diaphragm cases, actuators, pilots and control lines.

(f) Springs, orifices, or other parts should not be changed or modified without reevaluation of the above factors.

*1.2 Prevention of overpressuring downstream pressure-carrying components*.

Recognized methods of preventing overpressuring the downstream pressure-carrying components of control equipment include the following.

(a) Selecting equipment rated to withstand inlet pressure on the downstream side. This is particularly important if the equipment employs internal sensing and the adjacent downstream piping is not otherwise protected.

(b) Connecting the control or sensing line to the downstream pressure system where overpressure protection has been provided.

(c) Protecting the downstream pressure-carrying components by installing a relief valve, regulator, back-pressure valve, or other suitable device in the control or sensing line.

1.3 Flow reversals.

Flow reversals might alter operating pressures along a transmission line from their historical norms and patterns. A review of control equipment and set points should be conducted to confirm the adequacy of existing equipment under the new operating parameters.

*1.4 Reference.*

See guide material under §192.739.

## 2 OVERPRESSURE PROTECTION

*2.1 Facilities that might at times be bottle-tight*.

Suitable protective devices to prevent overpressuring of facilities that might at times be bottle-tight include the following.

(a) Spring-loaded relief valves meeting the provisions of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 (see §192.7).

(b) Pilot-operated back-pressure regulators used as relief valves which are designed so that failure of the control lines will cause the regulator to open.

(c) Rupture disks of the type meeting the provisions of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.

(d) Devices used to shut in natural gas wells feeding into gathering lines (e.g., well-pressure trip switches, slam shuts, Murphy switches).

*2.2 High-pressure distribution systems*.

Suitable devices to prevent overpressuring of high-pressure distribution systems include the following.

(a) Spring-loaded relief valves meeting the provisions of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.

(b) Weight-loaded relief valves.

(c) A monitoring regulator installed in series with the primary regulator.

(d) A series regulator set to continuously limit the pressure on the inlet of the primary regulator to not more than the maximum allowable operating pressure of the distribution system.

(e) An automatic shut-off device installed in series with the primary pressure regulator. The automatic shut-off device should be set to shut off when the pressure on the distribution system reaches a specified limit that does not exceed the maximum allowable operating pressure. Since this device remains closed until manually reset, it should not be used where it might cause an interruption in service to a large number of customers.

(f) Pilot-operated back-pressure regulators used as relief valves and designed so that failure of the control lines will cause the regulator to open.

(g) Spring-loaded diaphragm relief valves.

*2.3 Low-pressure distribution systems*.

Suitable protective devices to prevent overpressuring of low-pressure distribution systems include the following.

(a) A liquid-seal relief device that can be set to open accurately and consistently at the desired pressure.

(b) See 2.2(b) through 2.2(f) above.

*2.4 Transmission lines.*

In addition to the devices listed in 2.2 above, transmission lines may incorporate other suitable means, such as the following.

(a) Compressor overpressure protection (see guide material under §192.169).

(b) Automatic shut off valves or other similar devices that fail closed and require a manual reset.

(c) Rupture discs.

*2.5 Gathering lines.*

Gathering lines must use overpressure protection devices (§192.195(a)), such as those listed in 2.1, 2.2, 2.3, and 2.4 above. Overpressure protection devices could be located outside of the regulated segment.

*2.6 Other considerations.*

When bypass piping is included in the station design to facilitate maintenance or inspection of automatic overpressure protection devices, consideration should be given to the following.

(a) Providing a regulator on the bypass piping.

(b) Arranging the bypass piping for series regulators so that only one regulator at a time is bypassed.

(c) When only a manually operated bypass valve is installed:

(1) Providing upstream and downstream pressure gauges within sight of a person operating the manual valve, and

(2) Specifying a manual valve that is marked with the flow direction and the operating direction to close it.

## §192.197

## Control of the pressure of gas delivered from high-pressure distribution systems.

*[Effective Date: 10/15/03]*

**(a) If the maximum actual operating pressure of the distribution system is 60 psi (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.**

**[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]**

## GUIDE MATERIAL

(a) Suitable protective devices to prevent overpressuring of a customer's appliances — as a result of service regulator failure — with the conditions described in §192.197(b) include the following.
   (1) Monitoring regulator.
   (2) Relief valve.
   (3) Automatic shut-off device.

(b) The protective devices may be installed as an integral part of the service regulator or as a separate unit.

# §192.199

## Requirements for design of pressure relief and limiting devices.

*[Effective Date: 11/12/70]*

**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 over-pressuring, 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.**

**[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970]**

## GUIDE MATERIAL

### 1 RUPTURE DISKS

Rupture disks should meet the requirements for design as described in the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 (see §192.7).

### 2 CONTROL LINES

All control lines should be protected from falling objects, excavation, or other foreseeable causes of damage. They should be designed and installed so that damage to any one control line cannot render both the district regulator and overpressure protective device inoperative.

### 3 SINGLE INCIDENT (§192.199(g))

*3.1 General*.

In complying with §192.199(g), the operator should evaluate each district regulating station as to the type and extent of risks that may be expected. Different locations may suggest the need for individual station design, installation considerations and the ability to perform maintenance, inspection and testing activities.

*3.2 Examples*.

Among the incidents that should be considered in the design of a district regulator station are the following.

(a) Explosions or fire in vault.
(b) Damage by vehicles.
(c) Damage by earthmoving equipment.
(d) Weather and environmental effects.
(e) Others that might result from site selection with respect to airport and railroad operations.

*3.3 Protection*.

Design and installation considerations include the following.

(a) General.
  (1) Protection for relief valve stacks.
  (2) Selection of the type of overpressure protection.

(3) Evaluation of the need for redundant protection.
(4) Inspection or maintenance activities that could compromise the integrity of normal overpressure protection. See guide material under §192.739.

(b) Vaults.
(1) Use of a single vault, a double chamber vault, or vaults separated by an appropriate distance.
(2) Structural design. See guide material under §192.183.

(c) Above ground installations.
(1) Location on property under control of the operator.
(2) Space around building(s) for free movement of firefighting equipment.
(3) Use of a single-room building, a double-room building or buildings separated by an appropriate distance.
(4) Use of ventilated buildings made of noncombustible materials. The roof and sidewalls should be designed to relieve the force of an explosion.
(5) Use of posts, guardrails, or barricades.

## 4 SECURITY (§192.199(h))

Recommended methods for complying with §192.199(h) include the following.

(a) Securing the proper position of any valve under a relief valve that could make the relief valve inoperative or valves that could make the pressure regulating or limiting device ineffective, such as a bypass valve or a control line valve.
(b) Installing duplicate relief valves, each having adequate capacity to protect the system. Isolating valves or a three-way valve should be installed so that it is mechanically impossible to render more than one safety device inoperative at a time.

## 5 OTHER CONSIDERATIONS TO MINIMIZE DAMAGE BY OUTSIDE FORCES

See Guide Material Appendix G-192-13.

# §192.201

## Required capacity of pressure relieving and limiting stations.

*[Effective Date: 07/13/98]*

**(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.**

**[Amdt. 192-9, 37 FR 20826, Oct. 4, 1972; Amdt. 192-85, 63 FR 37500, July 13, 1998]**

## GUIDE MATERIAL

### 1 GENERAL

(a) The regulator capacity against which the relief device should protect is the maximum capacity under any single failure mode. The regulator capacity shown in the manufacturer's literature can be used, provided it is known to be the capacity of the regulator in a failed wide-open position. The capacity of the relief device should be based on the maximum capacity of the regulator at the highest pressure in the pipeline that supplies gas to the regulator. This supply pressure may be the maximum operating pressure or the maximum allowable operating pressure defined in §192.3.
(b) The minimum demand on a system may be considered when sizing the relief device provided there is assurance that this minimum flow will always be present.
(c) When there is parallel regulation at a station, the relief capacity for the station should be based on the assumption that the largest capacity regulator fails wide open.
(d) Consideration should also be given to the capacity of the pipeline system supplying the station. If the pipeline is not capable of supplying the failed wide-open capacity of the largest capacity regulator, the relief capacity may be based on the maximum capacity of the pipeline system supplying the station.

### 2 DETERMINATION OF RELIEF DEVICE CAPACITY

(a) When installed in accordance with the provisions of §192.199(f):
  (1) Relief devices stamped by the manufacturer with a capacity certified under the rules of the ASME Boiler and Pressure Vessel Code, Section VII (see §192.7), including recertification stampings, may be considered capable of relieving the capacity stamped. An adjustment should be made to determine the capacity at actual operating conditions.
  (2) Capacities listed in information published by the manufacturer may be used to identify the capacity of the relief device under the stated conditions.
  (3) The use of published data or data otherwise obtained from the manufacturer, and data calculated using recognized formulas, is acceptable.
(b) Relief device capacities as set out above are normally based on the pressure measured at the inlet to the relief device with discharge to atmosphere without vent stack piping. Therefore, when the installation is not in accordance with the provisions of §192.199(f), consideration should be given to the pressure loss in the inlet piping to the relief device, the control piping location and back pressure on the discharge side caused by vent stack piping.
(c) References include the following.
  (1) For the calculations in 2(a)(3) above, UG-131 of the ASME Boiler and Pressure Vessel Code, Section VIII. It is not the intent herein that the capacity be limited to 90% of the actual capacity as set out in Section VIII rules, but only that this information is useful in calculating the actual capacity of a relief device.
  (2) For data on relief devices which have been certified by the NBBI, "Relieving Capacities of Safety Valves and Relief Valves Approved by the National Board" (Discontinued).
  (3) For the effect of backpressure on relief device discharge, Figure D-1 of API RP 520 P2, "Sizing, Selection and Installation of Pressure-Relieving Devices in Refineries, Part 2 Installation."

# §192.203

## Instrument, control, and sampling pipe and components.

*[Effective Date: 07/13/98]*

**(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 ºF (204 ºC).**

**(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.**

**[Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998]**

### GUIDE MATERIAL

Instrument, control, and sampling pipe and components which extend to a remote location (adjacent room or building) should be identified by color code, signs, diagrams, or other appropriate means so that proper valves can be located and operated in an emergency. At locations where the identification of such piping is obvious, color coding, marking, diagrams, etc., may not be necessary. Also, see Guide Material Appendix G-192-13 and guide material under §192.199 and 192.739.

# §192.204

## Risers installed after January 22, 2019.

*[Effective Date: 01/22/19]*

**(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.**

**[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

*No guide material available at present.*

## §192.205
## Records: Pipeline components.

*[Effective Date: 07/01/2020]*

**(a) For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.**

**(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline.**

**(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of §192.624 according to the terms of that section.**

**[Amdt. 192-125, Oct. 1, 2019]**

### GUIDE MATERIAL

*This guide material is under review following Amendment 192-125.*

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## 3 FIELD JOINING (Plastic-to-plastic and plastic-to-metal)

*3.1 Solvent cement for repairing PVC piping only. (Plastic-to-plastic)*

*Note*: Editions of ASTM D2513 issued after 2001 no longer permit use of PVC piping for new installations, but do specify that it may be used for repair and maintenance of existing PVC gas piping. The Regulations may continue to reference an edition of ASTM D2513 earlier than 2001. The operator is advised to check §192.7 for IBR.

(a) The solvent cement and piping components may be conditioned prior to assembly by warming, provided that it is done in accordance with the manufacturer's recommendations. Special precautions are required when the surface temperature of the material is below 50 $^{o}$F or above 100 $^{o}$F.

(b) Square cut ends, free of burrs, are required for a proper socket joint. Beveling of the leading edge of the spigot end will provide for ease of insertion and better distribution of the cement.

(c) Proper fit between the pipe or tubing and the mating socket or sleeve is essential to a good joint. Before application of cement, the pipe or tubing should freely enter the fitting but should not bottom against the internal shoulder. Sound joints cannot normally be made between components that have a loose or very tight fit.

(d) A uniform coating of the solvent cement is required on both mating surfaces. A light coating should be applied to the socket and a heavier coating applied to the pipe or tubing. The pipe should be inserted immediately into the socket and bottomed in the socket.

For sizes greater than NPS 2, additional measures may be necessary to bottom the pipe. The completed joint should be held together for sufficient time to prevent the pipe from backing out of the fitting. After the joint is made, excess cement should be removed from the outside of the joint.

(e) The joint should not be subject to a pressure test until it has developed a high percentage of its ultimate strength. The time required for this to occur varies with the type of cement, humidity, and temperature.

(f) Other recommendations for making joints may be found in ASTM D2855 (for PVC), the Appendix of ASTM D2235 (for ABS), and the Appendix of ASTM D2560 (for CAB, but withdrawn 1986).

*3.2 Heat fusion for PA-to-PA and PE-to-PE only by externally applied heat. (Plastic-to-plastic)*

(a) PA and PE cannot be fused to each other.

(b) General training programs that include both printed material and slides are available from the Plastics Pipe Institute (see Guide Material Appendix G-192-1) and many manufacturers of plastic pipe.

(c) Care should be used in the heating operation. The material should be sufficiently heated to produce a sound joint but not overheated to the extent that the material is damaged.

(d) Square cut ends, free of burrs, are required for a proper joint.

(e) The mating surfaces should be clean, dry, and free of material which might be detrimental to the joint.

(f) The potential effect of drag force (the force required to initiate pipe movement) during butt fusion should be considered to ensure proper fusion pressure.

(g) Other recommendations for making heat-fusion joints may be found in ASTM F2620, “Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings”.

(h) References for joining PA-11 or PA-12 piping are PPI TR-45, "Butt Fusion Joining Procedure for Field Joining of Polyamide-11 (PA-11) Pipe" and PPI TR-50, “Generic Butt Fusion Joining Procedure for Field Joining of Polyamide-12 (PA12) Pipe."

(i) PE piping of different compounds or grades can be heat fused to each other. Such joining should not be undertaken indiscriminately, and should be undertaken only when qualified procedures for joining the specific compounds are used. Suggested references are as follows.

  (1) PPI TN-13, "General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings."

  (2) PPI TR-33, "Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe."

  (3) PPI TR-41, "Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping."

(j) Rain, cold, and windy weather conditions can influence fusion quality. Modification of the recommended heating time in the procedure should be given consideration during such conditions.

(k) For hot taps on PE, see guide material under §192.123.

(l) The condition of equipment for heat fusing PE must conform to the equipment manufacturer's recommended tolerances for acceptable wear of critical components. The use of damaged or worn equipment may result in fusion joints that are weak or out of alignment. The frequency of inspection should be determined by the operator based on equipment usage, equipment age and condition, and manufacturer's recommendation. See Guide Material Appendix G-192-20 for a sample inspection form.

(m) If an operator sees bubbles in the PE pipe melt pattern during the hot-plate heat fusion process (butt fusion, socket fusion, saddle fusion) or the fusion bead has a rough, pockmarked surface appearance, this is an indication that liquid hydrocarbons might have permeated the pipe wall– see 3.2(n) below for possible moisture exception. These bubbles are formed when the liquid hydrocarbons vaporize into the melt zone during the heating process. Heat fusion joining of pipes with liquid hydrocarbon might result in voids within the joint that could adversely affect joint strength. Regardless of whether suspected liquid hydrocarbons is a result of surrounding soil environment or contents of the pipe, mechanical couplings should be considered instead of heat fusion. Further, the operator should assess the pipeline's operating conditions and determine whether an adjustment to the design pressure is necessary per the guide material under §192.121. The identification of pipe compromised by liquid hydrocarbons should be included in the abnormal operating conditions identified for the task of joining plastic pipe.

(n) Driscopipe® 7000 and 8000 HDPE pipe high-density PE pipes on occasion are known to have moisture absorbed into the pipe wall which would form bubbles when heat is applied for heat fusion. If the operator suspects that these pipes contain moisture, the operator should contact the pipe manufacturer. An adjustment to the design pressure is not necessary per the guide material under §192.121 if moisture is present. See 3.2(m) above if there is suspicion of liquid hydrocarbon permeation.

*3.3 Heat fusion by electrofusion. (Plastic-to-plastic)*

(a) Sections 192.273 and 192.283 require that procedures for making joints other than by welding be written and qualified. Each electrofusion equipment manufacturer is a source of appropriate procedures for their respective system. The operator should check state requirements on the use of electrofusion. Generally each procedure should contain some or all of the following elements:

(1) *Couplings.*

(i) The pipe should be cut at a square angle.

(ii) The pipe should be marked with the proper stab depth for the fitting.

(iii) The mating surfaces should be clean, dry, and free of material that might be detrimental to the joint.

(iv) Surface oxidation should be removed from the area of the pipe to be fused, up to the stab-depth marks, using the tool specified in the qualified procedure.

(v) One end of the pipe should be secured in an appropriate clamping device, the fitting slid onto pipe, the second piece of pipe placed into clamp, and the fitting slid to final position onto each pipe so it is properly aligned. Insertion up to the stab-depth marks should be ensured.

(vi) The control box should be tested for proper function.

(vii) The fitting should be connected to the fusion control box and the cycle activated. The fitting should be left in the clamp until cooling has been completed.

(viii) The joint should be inspected in accordance with §192.273.

(2) *Saddle fittings.*

(i) Determine the pipe area where the fitting is to be fused.

(ii) The mating surfaces should be clean, dry, and free of material that might be detrimental to the joint.

(iii) All surface oxidation should be removed from the pipe in the area to be fused using the tool specified in the qualified procedure.

(iv) The fitting should be positioned and clamped in the cleaned area.

(v) The control box should be tested for proper function.
(vi) The fitting should be connected to the fusion control box and the cycle activated. The fitting should be left in the clamp until cooling has been completed.
(vii) The joint should be inspected in accordance with §192.273.

(b) ASTM F1055 (see §192.7) and ASTM F1290, "Standard Practice for Electrofusion Joining Polyolefin Pipe and Fittings" are references for joining plastic pipe by electrofusion.

(c) The electrofusion joining process does not allow visual examination of the pipe during the heating process to determine the presence of bubbles. If an operator suspects that liquid hydrocarbons or moisture might be present in the PE pipe, see 3.2(m) or 3.2(n) above.

*3.4 Adhesive for thermosetting pipe only. (Plastic-to-plastic)*

(a) The mating surfaces should be suitably prepared and should be dry and free of material that might be detrimental to the joint.
(b) Adhesive should be properly mixed and liberally applied on both mating surfaces. The assembled joint should be held together in alignment for sufficient time to prevent the pipe or tubing from backing out of the fitting.
(c) The assembled joint should not be disturbed until the adhesive has properly set. The joint should not be subjected to a pressure test until it has developed a high percentage of its ultimate strength. The time required for this to occur varies with the adhesive, humidity, and ambient temperature.
(d) To accelerate curing, an adhesive bonded joint may be heated in accordance with the manufacturer's recommendation.

*3.5 Mechanical joints for all plastic piping. (Plastic-to-plastic and plastic-to-metal)*

(a) When compression type mechanical joints are used, the elastomeric gasket material in the fitting should be compatible with the plastic; that is, neither the plastic nor the elastomer should cause deterioration in chemical or mechanical properties to the other over a long period.
(b) A stiffener is required for thermoplastic piping. The tubular stiffener required to reinforce the end of the pipe or tubing should extend at least under that section of the pipe compressed by the gasket or gripping material. The stiffener should be free of rough or sharp edges that could damage the piping. Stiffeners that fit the pipe or tube too tightly or too loosely may cause defective joining. The operator should check with the manufacturer for recommendations.
(c) The pull-out resistance of compression-type fittings varies with the type and size of the fitting and the wall thickness of the pipe being joined. ASTM D2513 (see §192.7) describes requirements for three categories of mechanical fittings.
    (1) Category 1 - full seal, full restraint. These types of mechanical fittings, when properly installed, are designed to provide a joint that is stronger than the piping being connected.
    (2) Category 2 - full seal, no restraint.
    (3) Category 3 - full seal, partial restraint.
(d) For each mechanical joint, it is required that the joining procedure be qualified by the tests in §192.283(b).
(e) Section 192.283(b)(4) requires that joints on pipe sizes less than NPS 4 must be able to withstand greater tensile forces than required to yield the plastic pipe (i.e., the pipe will yield before the mechanical joint). Joints for pipe sizes NPS 4 and greater must be able to sustain the tensile stresses as required by §192.283(b)(5). One of the methods for meeting these requirements is the use of Category 1 fittings.
(f) In addition to using qualified joining procedures for mechanical joints as discussed in 3(d) and (e) above, the operator should consider minimizing the longitudinal pull-out forces caused by contraction of the piping and the maximum anticipated external loading. To minimize these forces, practices such as the following should be used.
    (1) With direct burial, snaking the pipe in the ditch when the pipe is sufficiently flexible.
    (2) With insertion in a casing, pushing the pipe into place so that it is in compression rather than tension.
    (3) Allowing for the effect of thermal expansion and contraction of installed pipe due to seasonal changes in temperature. The importance of this allowance increases with the length of the

installation. This allowance may be accomplished by the following.

(i) Offsets.
(ii) Anchoring.
(iii) Strapping the joint.
(iv) Expansion-contraction devices.
(v) Fittings designed to prevent pull-out (ASTM D2513, Category 1).
(vi) Combinations of the above.

This allowance is important when the plastic pipe is used for insertion inside another pipe because it is not restrained. Coefficients of thermal expansion for thermoplastic materials determined using ASTM D696 are listed in Table 192.281i.

(g) Some plastic pipe mechanical joints, especially those made with older metal mechanical / compression fittings, have been known to leak or pull out due to not being of a full restraint design, or due to installation errors as pointed out in OPS Advisory Bulletin ADB-08-02 (73 FR 11695, March 4, 2008; see Guide Material Appendix G-192-1, Section 2). For this reason, consider using ASTM D2513-defined Category 1 (also known as Cat 1) fittings which, by design, provide for joints in plastic gas piping that are both full restraint and full seal. Such fittings are readily available for plastic gas piping in sizes through NPS 2 and some manufacturers supply Category 1 fittings in larger sizes. If Category 1 fittings are not used, another type of qualified joining procedure is required to be used as discussed in 3.5(d) and (e) above.

(h) When liquid hydrocarbons or moisture have permeated the PE pipe wall, see 3.2(m) or 3.2(n) above.

**COEFFICIENTS OF THERMAL EXPANSION**

| Pipe Material | Nominal Coefficients of Thermal Expansion [1] (x $10^{-5}$ in./in.)/(ºF) | Expansion (in./100 ft. pipe)/(ºF increase) |
|---|---|---|
| PA 32312 (PA 11) | 9.0 | 0.108 |
| PE 2406/PE 2708 | 9.0 | 0.108 |
| PE 3408/PE 4710 | 9.0 | 0.108 |
| PVC 1120 | 3.0 | 0.036 |
| PVC 2116 | 4.0 | 0.048 |

[1] Individual compounds may differ from the values in this table by as much as ±10%. More exact values for specific commercial products may be obtained from the manufacturer.

PA = polyamide

PE = polyethylene

PVC = poly (vinyl chloride)

**TABLE 192.281i**

# §192.283

## Plastic pipe: Qualifying joining procedures.

*[Effective Date: 03/12/21]*

**(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 pipe (PE) 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 nonlateral pipe connections, perform tensile testing in accordance with a listed specification. If the test specimen elongates no less than 25% or failure initiates outside the joint area, the procedure qualifies for use.**

**(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 D638 (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.**

**[Issued by Amdt. 192-34, 44 FR 42968, July 23, 1979 with Amdt. 192-34 Time Ext., 44 FR 50841, Aug. 30, 1979, Amdt. 192-34 Time Ext., 44 FR 57100, Oct. 4, 1979, Amdt. 192-34A, 45 FR 9931, Feb. 14, 1980, Amdt. 192-34B, 46 FR 39, Jan. 2, 1981, Amdt. 192-34 Correction, 47 FR 32720, July 29, 1982 and Amdt. 192-34 Correction, 47 FR 49973, Nov. 4, 1982; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85,63 FR 37500, July 13, 1998; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69**

**FR 54591, Sept. 9, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]**

## GUIDE MATERIAL

## 1 WRITTEN PROCEDURES

(a) An operator may elect to develop joining procedures or may adopt the joining procedures developed by groups such as the Plastics Pipe Institute, ASTM, gas association, or manufacturers. The operator is responsible for ensuring that the joining procedure used is qualified in accordance with the requirements of §192.283.

(b) Qualified joining procedures should, include images demonstrating the appearance of satisfactory joints. Written procedures for fitting installation are often packaged with each fitting.

(c) Qualified procedures should be in the operator's installation manuals and may be printed on wallet or shirt pocket cards, or made available by other means.

## 2 PROCEDURE QUALIFICATION (Plastic-to-plastic and plastic-to-metal)

*2.1 Procedure and qualification for joints and permanent repairs. (Plastic-to-plastic and plastic-to-metal)*

(a) Solvent cement, heat fusion, and adhesive. (Plastic-to-plastic)

(1) *Procedure.* A separate procedure should be established for each plastic compound and for each method of joining. The procedure specification should include the following as applicable.

(i) Plastic compound(s).
(ii) Joint design.
(iii) Size and thickness range.
(iv) Method of joining.
(v) Pipe and fitting preparation (e.g., scraping, peeling, facing, abrading).
(vi) Cleaning requirements.
(vii) Curing or set-up time.
(viii) Ambient temperature limits.
(ix) Temperature of the heating tool.
(x) Heating time.
(xi) Pressure.
(xii) Cooling time.
(xiii) Tools and equipment.
(xiv) Joining or repair technique. See 3 of the guide material under §192.281.

(2) *Qualification.* The procedure specification should be considered qualified if test assemblies of joints or repairs made in accordance with the procedure specification meet the requirements of 2.2 below. The test assemblies should be cured, set, or hardened in accordance with the manufacturer's recommendations.

(b) Mechanical. (Plastic-to-plastic and plastic-to-metal)

(1) *Procedure.* A separate procedure should be established for each kind and type of mechanical fitting to be used for making a joint or repair. It should include at least the following.

(i) Kind and type of plastic material(s).
(ii) Other piping elements to be joined to the plastic.
(iii) Joint design.
(iv) Size and thickness range.
(v) Type of mechanical fitting.
(vi) Tools and equipment.
(vii) Joining and repair procedure.

(2) *Qualification.* To qualify the procedure specification, test assemblies of joints or repairs should be made in accordance with the procedure specifications and tested in accordance with 2.2 below. The test assemblies may be restrained to the same extent that they would be in service.

These assemblies should be sectioned or dismantled to inspect for damage to the plastic pipe. The procedure should be rejected if there is evidence of damage that would reduce the service life of an installed joint or repair.

(3) *Other considerations.* See 3.5 of the guide material under §192.281.

*2.2 Test requirements. (Plastic-to-plastic and plastic-to-metal)*

Test assemblies should successfully meet the following requirements.

(a) Leak test. An assembly should not leak when subjected to a stand-up pressure test with air or gas.
(b) Short-term burst test. An assembly should meet the minimum burst requirements of ASTM D2513 or ASTM D2517, whichever is applicable (see §192.7 for both), for the specific kind and size of plastic pipe used in the assembly.
(c) Sustained-pressure test. An assembly should not fail when subjected to a sustained pressure test, such as the 1000 hr test described in ASTM D2513 or ASTM D2517 (whichever is applicable), for the specific kind and size of plastic pipe used in the assembly.
(d) Tensile test. An assembly should elongate no less than 25% or failure should initiate outside the joint area when subjected to ASTM D638 testing.
(e) Inspection. An assembly should be subjected to suitable nondestructive or destructive inspection to determine if the bonded area is substantially equivalent to the intended bond area.

## 3 UNLIKE PE COMPONENT QUALIFICATION

PE components made of different compounds and different grades of materials may be heat-fused, provided that properly qualified procedures for joining the specific compounds are used. Any combination of PE 2306, PE 2406/PE 2708, PE 3306, PE 3406, and PE 3408/PE 4710 may be joined by heat fusion using qualified procedures for specific materials. Operators attempting to qualify such procedures may be able to obtain qualified procedures from pipe manufacturers. (See guide material under §192.281 for PE heat fusion.) Additionally, the following references may be of assistance.

(a) PPI TN-13, "General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings."
(b) PPI TR-33, "Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe."
(c) PPI TR-41, "Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping."

# §192.285

## Plastic pipe: Qualifying persons to make joints.

*[Effective Date: 03/12/21]*

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

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

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

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

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

**(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.**

**[Issued by Amdt. 192-34, 44 FR 42968, July 23, 1979 with Amdt. 192-34 Time Ext., 44 FR 50841, Aug. 30, 1979, Amdt. 192-34 Time Ext., 44 FR 57100, Oct. 4, 1979, Amdt. 192-34A, 45 FR 9931, Feb. 14, 1980 and Amdt. 192-34B, 46 FR 39, Jan. 2, 1981; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]**

## GUIDE MATERIAL

### 1 OBSERVATION AND CERTIFICATION OF JOINER

Persons qualifying to make joints in plastic piping should be observed and certified by a qualified joiner while demonstrating their ability to make satisfactory joints using the correct procedure. See AGA XR0603, "Plastic Pipe Manual for Gas Service."

### 2 CERTIFICATION RECORDS

Records or qualification cards or both, which show the extent of the individual's qualifications, should be maintained for the qualification interval.

### 3 ULTRASONIC INSPECTION OF FUSION JOINTS

Ultrasonic inspection equipment should be capable of inspecting the internal bead for proper formation as well as detecting flaws in the fusion zone. Each manufacturer is a source of procedures for its equipment. The criteria for establishing an acceptable fusion joint must be verified by a destructive test and be repeatable. Each procedure should include the following.

(a) Cleaning the inspection area on both sides of the fusion joint.
(b) Using an appropriate manufacturer-approved couplant to couple the transducer to the pipe.
(c) Inspecting the entire pipe circumference on both sides of the fusion joint.

# §192.287

## Plastic pipe: Inspection of joints.

*[Effective Date: 07/14/04]*

**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.**

**[Issued by Amdt. 192-34, 44 FR 42968, July 23, 1979 with Amdt. 192-34 Time Ext., 44 FR 50841, Aug. 30, 1979, and Amdt. 192-34 Time Ext., 44 FR 57100, Oct. 4, 1979; Amdt. 192-94, 69 FR 32886, June 14, 2004]**

## GUIDE MATERIAL

*No guide material available at present.*

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(2) If the existing HDB is insufficient for the anticipated temperature, consider the potential of both temperature increase and decrease to ensure that the pipeline and joints are adequate for the longitudinal stresses imposed by temperature variations.
(3) Where the pipeline is installed in a casing, consider installing the pipe in a manner that minimizes thermal effects of heat transfer from the casing to the pipeline and prevents abrasion of the pipe due to thermal expansion and contraction of the plastic pipe. Methods to minimize thermal forces include the following.
   (i) Installation of spacers. The spacers should be placed sufficiently close together to prevent excessive deflection (sag) between the spacers for anchored and guided pipe. Consideration should be given to significant longitudinal stresses when deflection is minimized. Alternatively, the spacers may be placed at a sufficient distance to allow deflection between the spacers to reduce the longitudinal stress. In either case, the amount of deflection should not allow the pipe to contact the casing between spacers. It may be necessary to consider the thermal conductivity of the spacers if they are metallic.
   (ii) Filling the annular space between the pipe and its casing with a tight-fitting insulating material.

(b) Ultraviolet radiation.
Methods to protect plastic pipe from ultraviolet radiation include the following.
(1) Installation of pipe within a casing.
(2) Use of compatible external coating on the pipe.

(c) External damage.
(1) Position the pipeline to protect it from external damage. Consider providing additional protection, such as installation in a casing or utility tunnel.
(2) Where installed in a casing, the pipeline should be protected from shear forces imposed by soil or other loading at the ends of the casing.

(d) Chemical resistance.
Consider the installation environment (e.g., salts used on roads during winter, vehicle oils), and ensure that the plastic pipe is adequate for the exposure.

*8.2 Other considerations.*

(a) Other regulations. The agency having jurisdiction over the bridge should be consulted to determine if there are additional requirements.
(b) Casing end seals. Consider the installation of casing end seals to prevent water from entering the annular space between a casing and the pipeline.

(c) Valves. Consider installing valves to isolate the pipe on the bridge in case of a leak or failure.
(d) Seismic. Consider the effects of abnormal movement in areas of seismic activity.
(e) Joints. Butt fusion, electrofusion, or ASTM D2513 (see §192.7) Category 1 mechanical fittings should be used. However, Category 2 or Category 3 mechanical fittings may be used provided their joining procedure includes additional restraint as needed to meet the pullout requirements of §192.283(b).

*8.3 References.*

(a) ASME I00353, "Installation of Plastic Gas Pipeline in Steel Conduits Across Bridges."
(b) PPI Handbook of Polyethylene Pipe, Chapter 8, "Above-Ground Applications for Polyethylene Pipe."

## 9 INSTALLATION OF PA-11 or PA-12 PIPING FOR HIGHER PRESSURE APPLICATIONS

If PA-11 or PA-12 piping is installed for operating pressures up to and including 125 psig, standard installation procedures may be used. Section 192.121 limits PA-11 MAOP to 200 psig and PA-12 MAOP to 250 psig. If pressures exceed 125 psig, the following guidance should be considered.

*9.1 Installation.*

In addition to a method of locating (see 2.4 above), consider using a highly visible yellow warning tape (see 2.5 above) with a legend, such as "WARNING: Buried High Pressure Plastic Gas Pipeline."

*9.2 Pressure tests.*

Safety precautions similar to those used during other higher pressure pipeline tests should be employed due to the higher operating and test pressures for PA-11 or PA-12 piping. For example, PA-11 pipelines with an intended MAOP of 200 psig are required to be tested at 300 psig per §192.619(a)(2)(i).

*9.3 Hot taps.*

Currently, only mechanical or electrofusion hot-tapping tees are recommended for use on PA-11 or PA-12 piping. To avoid a blow-out when making hot taps using fusion fittings, the pressurized pipeline should not be heated above the manufacturer's recommendations. Consult the manufacturer for the appropriate hot-tapping joining method recommendations. See 3 of the guide material under §192.123.

## §192.323
## Casing.

*[Effective Date: 11/12/70]*

**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.**

### GUIDE MATERIAL

(a) Where plastic piping must be cased or bridged, suitable precautions should be taken to prevent crushing or shearing the piping. See guide material under §192.321.

(b) A reference for the design, installation, maintenance, repair, and monitoring of steel-cased pipelines is NACE SP0200, "Steel-Cased Pipeline Practice."

## §192.325
## Underground clearance.

*[Effective Date: 07/13/98]*

**(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).**

**[Amdt. 192-85, 63 FR 37500, July 13, 1998]**

**GUIDE MATERIAL**

**1 CLEARANCE**

*1.1 Transmission lines (§192.325(a)).*
If a minimum of 12 inches of clearance cannot be attained at the time of installation, less clearance may be allowed provided:
(a) Adequate measures are undertaken to prevent contact between the pipeline and the underground structure, such as encasement of the pipeline with concrete, polyethylene or vulcanized elastomer, or the installation of sand-cement bags, concrete pads or open-cell polyurethane pads in the space between the pipeline and the underground structure.
(b) Adequate measures are taken to prevent mechanical damage to the pipe and coating of multiple pipeline bundles installed by directional boring. Adequate measures should be employed to provide separation between the individual pipelines in the bundle in order to minimize damage to the pipe and coating. This may be accomplished by employing dielectric spacing devices (e.g., dense rubber spacers) or vulcanized elastomer spacers between the individual pipelines in the bundle. See §192.461(e).

*1.2 Mains (§192.325(b)).*
The following possible activities should be considered when determining the clearance to be attained between the main being installed and other underground structures.
(a) Installation and operation of maintenance and emergency control devices, such as leak clamps, pressure control fittings, and squeeze-off equipment.
(b) Connection of service laterals to both the main and other underground structures.
(c) For additional methods of protection in lieu of sufficient clearance, see 1.1(a) above.

*1.3 Clearance between plastic main or transmission line and any source of heat (§192.325(c)).*
The operator should consider the degree of the hazard presented by the heat source when determining the clearance, insulation, or protective material. For installations near electric or steam lines, the operator should also consider the following.
(a) A minimum radial separation of 12 inches is recommended by the Common Ground Alliance's "Best Practices" Guide, Practice Statement 2.12, available at https://commongroundalliance.com/best-practices-guide. See 5.3(d) of the guide material under §192.361.
(b) For installations near electric lines, see 5.3(e) of the guide material under §192.361.

**2 ADJACENT UNDERGROUND STRUCTURES**

When installing new mains or replacing existing mains, the proximity and condition of existing conduits, ducts, sewer lines, and similar structures, including abandoned structures, should be considered since they have the potential to provide a path for the migration of leaking gas.

## §192.327
## Cover.
*[Effective Date: 09/09/04]*

**(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 Inches (Millimeters) | 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).**

**[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-98, 69 FR 48400, Aug. 10, 2004]**

**GUIDE MATERIAL**

See Guide Material Appendix G-192-13.

## §192.328

## Additional construction requirements for steel pipe using alternative maximum allowable operating pressure.

*[Effective Date: 12/22/08]*

**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:**

**(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.**

**[Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

## GUIDE MATERIAL

*This guide material is under review following Amendment 192-124.*

## 1 MAIN CONNECTION AND PE PIPING

*1.1 General.*

The connection between a PE service line and the service tee at the main is particularly susceptible to excessive bending and shear stresses due to the design of the joint.

*1.2 Backfill and compaction.*

It is important that adequate backfill and compaction be provided in the transition area to reduce the stresses at the joint between the service tee and the plastic piping. Protective sleeves or bridging should also be considered if undue stresses are anticipated at these joints.

*1.3 Protective sleeves.*

(a) Purpose.
Protective sleeves mitigate excessive bending and shear stresses imposed on the plastic pipe at transition areas. Protective sleeve installations are in addition to providing adequate backfill and compaction around transition areas.

(b) Design.
(1) The protective sleeve should be designed to fully support the PE pipe in the joint area at the service tee.
(2) The protective sleeve should be of adequate length and inside diameter to ensure that the manufacturer’s minimum bend radius is not exceeded.
(3) The annulus between both the protective sleeve and the service tee, and the PE service line, should be of such fit to avoid overstressing the joint due to anticipated earth settlement after installation.
(4) Protective sleeves, supplied by several manufacturers, are typically lengths of either PE or PVC pipe.

*1.4 Bending at joints in PE piping.*

Due to the nature of installation, the service tee connection can experience excessive bending forces that are transmitted to the piping at the service tee joint.

(a) Bending of PE piping can overstress the joints, which can lead to premature failures. These concerns are heightened when making mechanical joints from steel service tees to PE pipe as the transition is from a rigid steel coupling to a flexible pipe, concentrating stresses at the transition area.

(b) The minimum bend radii recommendations from various PE piping manufacturers range from 90 to 125 pipe diameters depending on the PE used.

<u>Example:</u> NPS 1 (1.315" nominal outside diameter) PE piping containing a fitting in a bend should be bent at a bend radius no tighter than 118" to 164" depending on the specific pipe manufacturer's recommendation. (Where, 1.315" x 90 = 118"; 1.315" x 125 = 164".) Contact the piping manufacturer

for specific minimum bend radius recommendations.

*1.5 Other considerations.*
See guide material under §192.361.

**2 MAIN CONNECTION AND PA-11 or PA-12 PIPING**

See 9 of the guide material under §192.321.

## §192.369
## Service lines: Connections to cast iron or ductile iron mains.
*[Effective Date: 11/12/70]*

**(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.**

### GUIDE MATERIAL

See Guide Material Appendix G-192-18.

## §192.371
## Service lines: Steel.
*[Effective Date: 07/13/98]*

**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. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-85, 63 FR 37500, July 13, 1998]**

### GUIDE MATERIAL

No guide material necessary.

## §192.373
## Service lines: Cast iron and ductile iron.
*[Effective Date: 07/13/98]*

**(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.**

**[Amdt. 192-85, 63 FR 37500, July 13, 1998]**

## GUIDE MATERIAL

No guide material necessary.

# §192.375

## Service lines: Plastic.

*[Effective Date: 01/22/19]*

**(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;**

**(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.**

**(b) Each plastic service line inside a building must be protected against external damage.**

**[Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

## GUIDE MATERIAL

*This guide material is under review following Amendment 192-124.*

(a) One method of protecting that part of a plastic service line that is above ground or within a building from external damage is to completely enclose it in a metal pipe of sufficient strength. The metal pipe should have adequate protection against corrosion and should extend a minimum of 6 inches below grade for outside installations.

(b) For temperature limitations, see §192.123.

(c) For the installation of PA-11 or PA-12 piping for higher pressure application, see 9 of the guide material under §192.321.

(d) Plastic pipe may be temporarily installed above ground. For limitations and considerations on such use, see §192.321(g).

(e) For additional considerations relating to meter or service regulator locations, see guide material under §192.353.

# §192.376

## Installation of plastic service lines by trenchless excavation.

*[Effective Date: 01/22/19]*

**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.**

**[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

### GUIDE MATERIAL

(a) See Substructure Damage Prevention Guidelines for Directional Drilling and other Trenchless Technologies under Guide Material Appendix G-192-6**.**
(b) See Weak Link guide material under Guide Material Appendix G-192-15B, Section 5.

# §192.377

## Service lines: Copper.

*[Effective Date: 11/12/70]*

**Each copper service line installed within a building must be protected against external damage.**

### GUIDE MATERIAL

### 1 LOCATIONS

*1.1 Concealed*.

(a) Except when passing through walls and partitions, concealed locations should be avoided.
(b) When concealed locations are unavoidable, the service line should be located in hollow partitions rather than solid ones. The piping should be protected from physical damage by tools and other materials penetrating the wall or partition.

*1.2 Exposed*.

Consideration should be given to appropriate guards and additional supports when an exposed service line may reasonably be expected to be subject to physical damage due to normal activities in its vicinity.

### 2 SUPPORT

A horizontal run of service line should be supported to resist buckling or bending. The recommended maximum support spacing for commonly used tubing sizes is contained in Table 192.377i.

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# SUBPART I
# REQUIREMENTS FOR CORROSION CONTROL

## §192.451
### Scope.

*[Effective Date: 09/05/78]*

**This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]**

**GUIDE MATERIAL**

No guide material necessary.

## §192.452
### How does this subpart apply to converted pipelines and regulated onshore gathering pipelines?

*[Effective Date: 04/14/06]*

**(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 the 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 that is replaced, relocated or substantially altered.**

**(b) *Type A and B regulated onshore gathering lines.* For any Type A or B 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.**

**(c) *Type C onshore regulated gathering lines*. For any Type C onshore regulated gathering pipeline under §192.9 existing on May 16, 2022, that was not previously subject to this part, and for any Type C onshore gas gathering pipeline that becomes subject to this subpart after May 16, 2022, because of an increase in MAOP, change in class location, or presence of a building intended for human occupancy or other impacted site:**

**(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.**

**(d) *Regulated onshore gathering lines generally.* Any gathering line that is subject to this subpart per §192.9 at the time of construction must meet the requirements of this subpart applicable to pipelines installed after July 31, 1971.**

**[Issued by Amdt. 192-30, 42 FR 60146, Nov. 25, 1977; Amdt. 192-102, 71 FR 13289, Mar. 15, 2006; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021]**

**GUIDE MATERIAL**

The operator should review the corrosion control records or perform field tests and surveys for a pipeline being converted according to §192.14 or a newly regulated segment of gathering line to ensure that cathodic protection can be applied to the pipeline to meet the requirements of Subpart I within 12 months of the conversion or becoming regulated. The tests and surveys may include electrical surveys, pipe examination, coating examination and soil tests. A record of the review or tests and surveys should be maintained.

## §192.453

## General.

*[Effective Date: 02/11/95]*

**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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994]**

**GUIDE MATERIAL**

### 1 PERSONNEL QUALIFICATIONS

Personnel responsible for directing the design, installation, operation, or maintenance of an operator's corrosion control systems should have knowledge of and practical experience in the following.

(a) Pipeline coatings.
(b) Cathodic protection (CP) systems (galvanic and impressed current).
(c) Stray current interference.
(d) Electrical isolation.
(e) Survey methods and evaluation techniques.
(f) Instruments used.

### 2 REFERENCE

A reference for the design and installation of CP systems is NACE SP0169, Sections 7 and 8.

## §192.455

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

*[Effective Date: 01/22/19]*

**(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:**

**(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 six 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 five years beyond installation, corrosion during the five-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 8.0, 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.**

**(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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-28, 42 FR 35653, July 11, 1977; Amdt. 192-39, 47 FR 9842, Mar. 8, 1982; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

## GUIDE MATERIAL

*This guide material is under review following Amendment 192-124.*

## 1 REFERENCES

NACE SP0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," as follows.

(a) For §192.455(a), see Sections 7, 8, and 9.

(b) For §192.455(b), see Section 3.

## 2 ISOLATED STEEL COMPONENTS IN PLASTIC PIPING SYSTEMS

**(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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971]**

**GUIDE MATERIAL**

Amphoteric metal, as defined in NACE SP0169, is a metal that is susceptible to corrosion in both acid and alkaline environments (e.g., aluminum and copper).

## §192.465

## External corrosion control: Monitoring.

*[Effective Date: 03/12/2021]*

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

**(1) Each cathodic protection rectifier or impressed current poser source must be inspected sic times each calendar year, but with intervals not exceeding 2 ½ months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier.**

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

**(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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-35, 44 FR 75384, Dec. 20, 1979 with Amdt. 192-35A, 45**

**FR 23441, Apr. 7, 1980; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192.93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010]**

## GUIDE MATERIAL

### 1 METHODS FOR MONITORING CATHODICALLY PROTECTED PIPELINES

(a) Monitoring requirements of pipeline cathodic protection (CP) systems may be satisfied by on-site, remote, or other testing and inspection methods.
(b) A rectifier or other cathodic protection device protecting a regulated segment of gathering line could be located outside the limits of the regulated pipe segment.

### 2 REMEDIAL ACTION TO CORRECT DEFICIENCIES FOUND BY MONITORING

(a) Common corrosion control methods include coating, CP, and electrical isolation. CP systems typically use galvanic anodes or impressed current (rectifiers). Other corrosion control devices may include electrical isolators, interference bonds, diodes, and reverse current switches.
(b) Remedial action is required whenever it is determined that the CP or other installed corrosion control methods are not operating effectively.
(c) The specific remedial action to be taken depends on the type of corrosion control method installed and the problem encountered. In certain situations, the deficiency can be corrected by modifying existing corrosion control methods (e.g., increasing output from adjacent rectifiers).
(d) Operators are required to take prompt remedial action to correct deficiencies indicated by monitoring. Remedial action should correct the deficiency before the next monitoring cycle required by §192.465. However, for monitoring cycles greater than one year, remedial action should be completed within 15 months of discovery.
Example: It is discovered that pipe coating has deteriorated and that the existing corrosion control system is unable to achieve the desired CP level. The operator should initiate and document action taken to achieve the acceptable CP level before the next monitoring cycle. Remedial action might include the following.
(1) Installing additional CP,
(2) Recoating the pipe to meet the requirements of §192.461, or
(3) Replacing the pipe.
(e) If remedial action cannot be completed prior to the next scheduled monitoring cycle, the operator should document the actions taken to correct the deficiency and the expected timeframe for completion.

### 3 METHODS FOR LOCATING CORROSION AREAS ON UNPROTECTED PIPELINES

(a) Unprotected pipeline as used in §192.465(e) means a metallic pipeline (other than cast iron and ductile iron) that is not cathodically protected in accordance with §192.463. The most effective, practical, and reliable methods to evaluate or determine areas of corrosion on gas facilities will vary with the type and location of facilities. Historically, electrical-type surveys have been practical and effective on transmission pipelines and other pipelines in rural areas (see 9 below). In-line inspection (ILI) may also be useful where the pipeline will accommodate this equipment (see Guide Material Appendix G-192-14). Pipelines in urban areas present great difficulty in the use of ILI tools and in the practical application and interpretation of electrical-type surveys. The use of such surveys will generally be precluded in urban areas by the considerations in 9.2 below.
(b) Where electrical-type surveys are considered impractical or ineffectual, leak surveys and a review of leak survey results, corrosion leak repair history, and records of exposed pipe examinations are the most effective means of determining corrosion areas. In addition, §192.465(e) requires an operator to consider the pipeline environment that could affect the probability of active corrosion. Leak surveys and records review may be the most appropriate method to determine corrosion areas on distribution

gas facilities and other gas facilities in urban areas. On-stream corrosion detectors, pressure tests, ultrasonic, acoustical, visual, or other methods may be applicable in special cases.

## 4 DETERMINING ACTIVE CORROSION ON UNPROTECTED PIPELINES

*4.1 Considerations.*

The determination that active corrosion exists depends on an assessment of whether conditions in known or suspected corrosion areas are such that continuing corrosion could result in a detriment to public safety. For determining if a known or suspected corrosion area involves continuing corrosion, use personnel who are qualified in corrosion control methods (see §192.453 and Subpart N for qualification requirements, as applicable). For determining if a detriment to public safety could result, the operator should use personnel who are, at a minimum, qualified by training or experience. The following factors should be considered in assessing the effect on public safety.

(a) Leak frequency.
(b) Pressure.
(c) Location of piping.
(d) Location of dwellings and other structures.
(e) Gas venting and migration characteristics of the area.

*4.2 Determination.*

Continuing corrosion should be considered as active corrosion if it is determined that operation and maintenance actions will not control the corrosion condition to an extent that prevents it from becoming detrimental to public safety.

## 5 "NOT ACTIVE" CONTINUING CORROSION ON UNPROTECTED PIPELINES

(a) If continuing corrosion is determined to be "not active," CP or other corrective measures may not be required. One method of assessing continuing corrosion is by a measured or calculated corrosion rate of the pipe in the area of concern. Application of the corrosion rate to the pipe could result in an estimate of when the pipe might become a detriment to public safety. Corrective measures would be required prior to that time. Such an analysis would be required at least every three years at intervals not exceeding 39 months, since §192.465(e) requires an unprotected pipeline be reevaluated every three years at intervals not exceeding 39 months for the existence of active corrosion.
(b) Corrosion that is currently considered "not active" could also become active due to growth of public presence in the vicinity of the pipeline. An increase in the rate of corrosion is not necessarily required.

## 6 CORRECTING ACTIVE CORROSION ON UNPROTECTED PIPELINES

*6.1 Corrective measures.*

Where it has been determined that active corrosion exists, §192.465(e) requires CP in accordance with Subpart I for the pipeline in areas of active corrosion. The following corrective measures should be considered.

(a) Cathodically protecting the pipeline in areas of active corrosion. The following measures should be considered to assist in the application of CP.
    (1) Coating or recoating the pipe.
    (2) Controlling stray current.
    (3) Mitigating CP current shielding effects or non-galvanic corrosion, such as microbiologically influenced corrosion (MIC).
(b) Replacing with plastic pipe or coated steel pipe.
(c) Abandonment.

*6.2 Prompt action.*

Operators should take prompt action when an area of active corrosion is found. Corrective action should be completed within 15 months of discovery, or earlier if analysis indicates a shorter interval is appropriate. If corrective action cannot be completed within 15 months, the operator should document the actions taken and the expected timeframe for completion.

*6.3 Reference.*
AGA XL0702, "Distribution Pipe: Repair and Replacement Decision Manual."

## 7 MONITORING OF CATHODICALLY PROTECTED AREAS ON UNPROTECTED PIPELINES (§192.465(a))

7.1 "Active" corrosion areas.
See 4 and 6 above. For areas of local corrosion protection provided by galvanic anodes at individual locations of active corrosion, the anodes need to provide a level of CP that complies with §192.463. Monitoring is required in accordance with §192.465(a).

*7.2 "Not active" corrosion areas.*
See 5 above. For areas of local protection provided by galvanic anodes at individual locations of "not active" corrosion, the corrosion protection levels are not subject to the requirements of §192.463. Such "voluntarily installed" anodes need not be monitored in accordance with §192.465(a), but the pipeline must be reevaluated every three years at intervals not exceeding 39 months in accordance with §192.465(e).

## 8 MONITORING OF UNPROTECTED PIPELINES (§192.465(e))

Every three years at intervals not exceeding 39 months, unprotected pipelines are required to be reevaluated to identify areas of active corrosion in accordance with §192.465(e). Electrical surveys are required except as follows.

(a) Where electrical survey is impractical, the study of failures, leakage history, corrosion, class location, hazard to the public, and unusual operating/maintenance conditions may be used to evaluate the need for protection.
(b) Where the pipeline is remotely located or otherwise determined that corrosion caused leaks would not be a detriment to public safety.

## 9 USING ELECTRICAL-TYPE SURVEYS FOR UNPROTECTED PIPELINES

*9.1 Methods.*

(a) The following are examples of electrical-type surveys.
    (1) Pipe-to-soil potential measurement. Where practical, this electrical survey is required by §192.465(e) to determine areas of active corrosion on transmission lines.
    (2) Soil resistivity measurement.
    (3) Dual electrode or earth gradient measurement.
    (4) Line current measurement.
(b) Except for pipe-to-soil potential surveys, if other electrical-type surveys are used to determine areas of active corrosion, §192.465(e) requires a review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

*9.2 Applicability*
Where electrical-type surveys are considered for use in determining corrosion areas, the operator should consider the following conditions that may make these surveys impractical to apply or ineffective, or may result in unreliable data.

(a) Stray earth gradient. Telluric currents, iron ore deposits, A.C. induction, and other sources create stray earth potential gradients that may make it difficult to reliably interpret electrical surveys.
(b) Lack of electrical continuity. The facility may not be electrically continuous due to unknown insulators or other high resistance joining methods, such as gasketed joints and, on occasion, lack of continuity on threaded connections. These discontinuities may be intermittent with time.

(c) Pavement and congestion. Electrical-type surveys are complicated in congested areas where frequent pipe contact is necessary. Paved streets and sidewalks prevent ready access to the soil contact required for the copper sulfate electrode and also limit ability to contact the pipe itself.
(d) Electrical isolation. Facilities that are not electrically isolated are often in direct contact with other metallic structures or in indirect contact with these structures through the earth, house plumbing, wiring, or electrical grounding systems. Where such contacts exist, electrical surveys are either ineffective or may erroneously indicate corrosion problems. For example, an unknown contact between a steel pipeline and aluminum, zinc, or galvanized metal would indicate an electro-negative peak on a pipe-to-soil survey that may erroneously be interpreted as a corrosive condition on the pipeline.
(e) Shielding of CP current. CP current can be shielded from the pipeline by nearby objects close to the pipeline. The current can be picked up by nearby conducting elements such as casings, parallel or crossing lines, scrap metal, or other foreign objects. Non-conducting elements close to the pipeline can also shield or limit the current to the pipeline. Such elements could be disbonded coating, rocks, solid-type abrasion protection or rock shield material (i.e., material that would shield CP current), rock ledges, or concrete structures. The shielding effects can go undetected by an electrical survey due to the many combinations of the size and location of shielding objects.
(f) Sufficiency of history and details of facilities. Correct interpretation of electrical measurements on gas facilities depends on detailed knowledge of the age and types of material installed, maintenance history, location of galvanic anodes, coating, foreign facilities, location and types of service lines, joining methods, and unusual soil conditions. For example, the installation of insulators after the facilities have been in service will alter the significance of previous electrical survey data.
(g) Other conditions.
    (1) Extremely dry soil.
    (2) Adjacent underground facilities.
(h) Practicability. The extreme hardship or expense of obtaining a meaningful electrical survey may render a survey inappropriate for a given pipeline because of the above or other conditions.

### 10 IN-LINE INSPECTION SURVEYS

An increase in the number or severity of corrosion defects discovered during assessments might indicate that remedial action is needed (see 2 above). For information about in-line inspection surveys, see Guide Material Appendix G-192-14.

## §192.467

### External corrosion control: Electrical isolation.

*[Effective Date: 09/05/78]*

**(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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]**

## GUIDE MATERIAL

### 1 INSPECTION AND TESTING (§192.467(d))

The required monitoring of cathodic protection (CP) systems and the evaluation of CP test data is generally sufficient to ensure that electrical isolation is adequate on cathodically protected piping. However, specific electrical tests on insulating devices should be made where deemed necessary to ensure the adequacy of electrical isolation and to pinpoint operational problems on CP systems. The operator should establish criteria for casing and carrier pipe CP readings that indicate a metallic short or electrolytic contact. Factors to consider when establishing criteria include the following.

(a) Capabilities of equipment.
(b) Environment of casing and carrier pipe.
(c) Coated versus bare pipe.
(d) Depth of casing.

### 2 ELECTRICAL ISOLATION (§192.467(a), (b), and (c))

*2.1 Insulating devices. (§192.467(a) and (b))*

Insulating devices may consist of insulating flange assemblies (see guide material under §192.147), unions or couplings, or fabricated insulating joints. These devices should be properly rated for temperature, pressure, and dielectric strength. Typical locations where electrical insulating devices should be considered include the following.

(a) At supporting pipe stanchions, bridge structures, tunnel enclosures, piling, and reinforced concrete foundations where electrical contact would preclude effective cathodic protection (CP). It may be necessary to electrically isolate the piping from such a structure, or the piping and structure from adjacent underground piping.
(b) At metallic curb boxes and valve enclosures. These should be designed, fabricated and installed in such a manner that electrical isolation from the piping system will be maintained.
(c) Where a pipe enters a building through a metallic wall sleeve and where it is intended to maintain electrical isolation between the sleeve and the pipe. To accomplish this, insulating spacers should be used.
(d) At river weights, pipeline anchors, and metallic reinforcement in weight coatings. These should be electrically isolated from the carrier pipe and installed so that coating damage will not occur.
(e) Points at which facilities change ownership, such as meter stations and well heads.
(f) Connections to main line piping systems, such as gathering or distribution system laterals.
(g) Inlet and outlet piping of inline measuring or pressure regulating stations or both.
(h) Compressor or pumping stations, either in the suction and discharge piping or in the main line immediately upstream and downstream of the station.
(i) In stray current areas.
(j) At the termination of service line connections and entrance piping to prevent electrical continuity with other metallic systems.

*2.2 Casings. (§192.467(c))*

(a) New installations.
   (1) *Spacers and sealing.* All new construction of cased metallic pipelines should provide for the installation of insulating type casing spacers or other suitable means to prevent physical contact between the carrier pipe and casing. The ends of the casing may be sealed with a

non-conductive sealing method to prevent mud, silt, and water from entering the annular space between the casing and the carrier pipe. It may be necessary to fill this annular space with a non-conductive type casing filler to ensure continued isolation in those installations where end seals alone may not be sufficient to resist the entrance of water.

(2) *Joining.* Lengths of casing should be joined by a full weld, or other type of joint that will provide an adequate seal against water entrance. Any holes in the casing should be closed by welding, or otherwise sealed.

(3) *Insertion*. Care should be taken during installation to reduce the possibility of electrical shorts. The carrier pipe should be as straight as practical. The internal diameter of the casing should be adequate to ensure physical clearance from the carrier pipe. The carrier pipe should be carefully inspected and all coating damage repaired. Care should be taken during insertion of the carrier pipe. To prevent damage to the coating and spacer, the casing should be clear of any mud, water, or debris prior to insertion of the carrier pipe. When existing buried pipe is being used as the casing, steps should be taken to ensure that the casing pipe is free of weld protrusions and other obstructions that might cause jamming of the carrier pipe during insertion.

Where insulating-type casing spacers are used, one should be installed as close as practical to each end of the casing. Vent connections, when required, should be installed prior to the insertion of the carrier pipe to preclude the possibility of damage to the carrier pipe.

(b) Existing installations.

(1) Where there is an indication that corrosion is occurring on the carrier pipe or where a CP installation is rendered inadequate as a result of low resistance between the casing and carrier pipe (i.e., the pipe-to-soil and the casing-to-soil readings are essentially the same), the operator should test the casing to confirm if a metallic short or electrolytic contact actually exists. It is recommended that the casing be tested within one year of discovering the indication. Consideration should be given to additional measures such as leakage surveys (see (3)(iv) below) until the test is conducted.

(2) The following are types of tests that can be used to determine if a carrier pipe is likely to be in metallic or electrolytic contact with a casing. For guidance on how to perform these types of tests, see the related source documents.

(i) Direct Current Voltage Gradient (DCVG) – Reference NACE TM0109, “Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition.”

(ii) AC current attenuation – Reference NACE TM0109, “Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition.”

(iii) Alternating Current Voltage Gradient (ACVG) – Reference NACE TM0109, “Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition.”

(iv) Potential surveys – Reference NACE TM0497, “Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems.”

(A) Potential Surveys (CIS, No Interruption).

(B) Potential Surveys (CIS, Interrupted).

(v) Pipe or cable locator – Reference NACE SP0200, “Steel-Cased Pipeline Practices.”

(vi) Current span test / Four-Wire Drop Test – Reference NACE SP0200, “Steel-Cased Pipeline Practices.”

(vii) Internal resistance test – Reference NACE SP0200, “Steel-Cased Pipeline Practices.”

(viii) Panhandle Eastern Test.

(ix) Casing or pipe capacitance.

(x) Temporary intentional short.

(3) Mitigative measures.

(i) Electrolytic contact. If the test determines that an electrolytic contact exists (water or dirt in contact with the pipeline at a coating holiday), an operator may choose one or more of the following measures to eliminate the contact.

(A) Clean out the casing and replace or repair the end seals on the casing.

(B) Fill the annular space between the carrier pipe and casing with a non-conductive (i.e., dielectric) filler. When filling the annular space, the operator should confirm that the actual amount of fill material is consistent with the annular volume. For additional installation guidance, see NACE SP0200, "Steel-Cased Pipeline Practices."

(C) Replace with an uncased pipeline.

(D) Remove the casing if the carrier pipe has sufficient strength for the anticipated stresses and determine if the requirements of §192.111 are applicable for the uncased crossing.

(ii) Metallic short. If the test determines that a metallic short exists, an operator may choose one or more of the following measures to eliminate or mitigate the short.

(A) Clear the short. It may be practical to expose the ends of the casing and physically realign the carrier pipe to give enough clearance for inserting a non-conductive material in the annular space between the casing and carrier pipe. The feasibility of safely moving the carrier pipe to clear a short should be determined prior to performing the work. See 4 of the guide material under §192.703.

(B) Fill the annular space. The space between the carrier pipe and casing may be filled with a non-conductive (i.e., dielectric) material. When filling the annular space, the operator should confirm that the actual amount of fill material is consistent with the annular volume.

(C) Replace with an uncased pipeline.

(D) Remove the casing if the carrier pipe has sufficient strength for the anticipated stresses and determine if the requirements of §192.111 are applicable for the uncased crossing.

(iii) Completion check. The operator should verify the effectiveness of mitigative actions taken under 2.2(b)(3)(i) or (ii) above. For the types of tests, see 2.2(b)(2) above.

(iv) Interim action. It is recommended that until one of the above measures can be implemented, the operator should consider one or more of the following actions.

(A) Conduct instrumented leak detection inspections at the same intervals as prescribed for patrolling in §192.705.

(B) Review existing in-line inspection (ILI) tool runs to determine the condition of the pipe inside the casing.

(C) Run an ILI tool that detects metal loss on the carrier pipe.

(D) Perform Guided Wave Ultrasonic Technology (GWUT) on the carrier pipe in the casing.

## 3 COMBUSTIBLE ATMOSPHERE (§192.467(e))

(a) Precautions to prevent arcing may be taken by installing galvanic anode type grounding cells or commercial lightning or fault arrestors across the insulating devices.

(b) Where lightning arrestors are installed across insulating devices within a building or other confined space anticipated to have a combustible atmosphere, the physical installation of the lightning arrestors should be made outside the confined space. Electrical conductors of adequate size should be installed from the insulating point to the lightning arrestors.

## 4 PROTECTION OF INSULATING DEVICES (§192.467(f))

It is recommended that the operator make a study in collaboration with the electric company on the common problems of corrosion and electrolysis, taking into consideration the following factors.

(a) The possibility of the pipeline carrying either unbalanced line currents or fault currents.

(b) The possibility of lightning or fault currents inducing voltages sufficient to puncture pipe coatings or pipe.

(c) CP of the pipeline, including the location of ground beds. (This is particularly important if the electric line is carried on steel towers.)

(d) Bonding connections that exist between the pipeline and the overhead electric system at the following.

(1) The steel tower footing.

(2) The buried grounding facility.
(3) The ground wire.

(e) Protection of insulating joints in the pipeline against induced voltages or currents resulting from lightning strikes. This can be obtained by the following.
(1) Connecting buried sacrificial anodes to the pipe near the insulating joints.
(2) Bridging the pipeline insulator with a spark-gap.
(3) Other effective means.

(f) Cable connections from insulating devices to lightning and fault current arrestors should be short, direct, and of a size suitable for short-term, high current loading.

(g) The electrical properties of nonwelded joints. (Where the objective is to ensure electrical continuity, it may be achieved by using fittings manufactured for this purpose or by bonding the mechanical joints in an approved manner. Conversely, if an insulating joint is required, a device manufactured to perform this function should be used. In either case, these fittings should be installed in accordance with the manufacturer's instructions.)

## 5 REFERENCES

(a) NACE SP0177, "Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems."
(b) NACE SP0200, "Steel-Cased Pipeline Practices."

# §192.469

## External corrosion control: Test stations.

*[Effective Date: 11/01/76]*

**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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976]**

### GUIDE MATERIAL

## 1 CONTACT POINTS

Any contact point location (e.g., valves, blowoffs, meters, service lines, regulators, regulator vents and platform risers, which are electrically continuous with the structure under test) may be chosen for testing as long as the level of cathodic protection is effectively determined.

## 2 TEST LEADS

Some typical test lead locations include the following.
(a) Pipe casing installations.
(b) Foreign metallic structure crossings.
(c) Insulating joints.
(d) Waterway crossings.
(e) Bridge crossings.
(f) Road crossings.
(g) Galvanic anode installations.
(h) Impressed current anode installations.

# §192.471

## External corrosion control: Test leads.

*[Effective Date: 08/01/71]*

**(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.**

**[Issued by Amdt 192-4, 36 FR 12297, June 30, 1971]**

### GUIDE MATERIAL

### 1 INSTALLATION METHODS

Some acceptable methods include the following.

*1.1 Thermit welding*.

(a) Steel. Attachment of electrical leads directly to steel pipe by the thermit welding process using copper oxide and aluminum powder. The thermit welding charge should be limited to a 15-gram cartridge.

(b) Cast iron. Attachment of electrical leads directly to cast or ductile-iron pipe by the thermit welding process using copper oxide and aluminum powder. The thermit welding charge should be limited to a 32-gram cartridge.

*1.2 Solder connections*.

Attachment of electrical leads directly to steel pipe with the use of soft solders or other materials that do not involve temperatures exceeding those for soft solders.

*1.3 Brazing*.

Attachment of electrical leads to steel pipe by brazing, provided that the pipeline operates at less than 29% SMYS.

*1.4 Mechanical connections*.

Mechanical connections which remain secure and electrically conductive.

### 2 OTHER CONSIDERATIONS

For convenience, conductors may be coded or permanently identified. Wire should be installed with slack. Damage to insulation should be avoided. Repairs should be made if damage occurs. Test leads should not be exposed to excessive heat or excessive sunlight.

# §192.473

## External corrosion control: Interference currents.

*[Effective Date: 09/05/78]*

level.

(f) Use of material for vent tubing that is compatible with the environment encountered. For example, some kinds of plastic tubing should not be exposed to direct sunlight, and certain aluminum alloys should not be submerged or placed in contact with concrete.

# §192.481

## Atmospheric corrosion control: Monitoring.

*[Effective Date: 03/12/21]*

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

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

**(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.**

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

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]**

**GUIDE MATERIAL**

**DETERMINING AREAS OF ATMOSPHERIC CORROSION**

(a) Type A and B gathering line overpressure devices or valves that lie outside of the regulated segments (see §192.8(b)) are not required to have inspections for atmospheric corrosion.

(b) The presence of atmospheric corrosion can be detected best by visual inspection.
  (1) This may require ladders, scaffolds, hoists, or other suitable means of permitting inspector access to the structure being inspected. In addition to the locations listed in §192.481(b), attention should be given to locations such as clamps, rest plates, and sleeved openings.
  (2) Piping that is thermally or acoustically insulated (jacketed) should be inspected wherever practical. To minimize damage to the insulation, a visual inspection of the pipe may be performed by cutting

windows into the insulation.

(c) Exposure test racks can be used to evaluate coatings and materials in local environments such as industrial, coastal, and offshore locations. Many standard procedures or test methods for evaluating materials and coatings are available from the ASTM International.

(d) Evidence of atmospheric corrosion on meters and regulators may also be determined by inspection by operator employees such as meter readers and leak survey personnel.

## §192.483

## Remedial measures: General.

*[Effective Date: 08/01/71]*

**(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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971]**

**GUIDE MATERIAL**

No guide material necessary.

## §192.485

## Remedial measures: Transmission lines.

*[Effective Date: 03/06/15]*

**(a) *General corrosion*. Each segment of transmission line pipe 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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]**

## GUIDE MATERIAL

## 1 EVALUATION

*1.1 Introduction*.

The evaluation of the pressure strength of a corroded region in a transmission pipeline to determine its suitability for continued service can be made by an analytical method, by pressure testing, or by an alternate method.

*1.2 Pressure testing*.

The pipe containing the corroded region may be pressure tested to confirm the established MAOP, or to determine a lower MAOP. The pressure test should be in accordance with the general requirements of Subpart J (in particular §192.503), and the pressure should be held for at least 8 hours. The established MAOP may be confirmed by testing to a pressure at least equal to the MAOP times the appropriate factor in Table 192.485i or ii below. A lower MAOP may be established by dividing the successful test pressure by the appropriate factor.

(a) For pipeline segments that have not been confirmed for operation in the next higher class location, see §192.611:

| CLASS LOCATION | FACTOR |
|---|---|
| Class 1 locations<br>• No buildings for human occupancy within 300 feet<br>• With buildings for human occupancy within 300 feet | <br>1.10<br>1.25 |
| Class 2 locations | 1.25 |
| Class 3 & 4 locations and Meter & Compressor Station piping in Class 1 & 2 locations | 1.5 |

**TABLE 192.485i**

(b) For pipeline segments that are required to be qualified for an existing class location, see §192.611:

| CLASS LOCATION | FACTOR |
|---|---|
| Class 2 | 1.25 |
| Class 3 | 1.50 |
| Class 4 | 1.80 |

**TABLE 192.485i**

*1.3 Alternate Method*

For conditions of low stress level, the following method may be used. An MAOP, not to exceed the established MAOP, may be determined by the following formula:

$$P = \frac{2St_rT}{D}$$

Where:

| | | |
|---|---|---|
| $P$ | = | MAOP (not to exceed established MAOP), psig |
| $S$ | = | Hoop stress, psig |
| $t_r$ | = | Actual remaining wall thickness at point of deepest corrosion, inches |
| $T$ | = | Temperature derating factor, see §192.115 |
| $D$ | = | Nominal outside diameter (see Table 192.105i), inches |

*S* must not exceed 72% SMYS in Class 1 locations, 60% in Class 2 locations, 50% in Class 3 locations, and 40% in Class 4 locations.

## 2 REPAIR OR REPLACEMENT

If a pipeline has an area of external corrosion that disqualifies it for service at the established MAOP, or if the MAOP cannot be reduced to the indicated safe level, it should be repaired or replaced. For acceptable methods of repair, see 3 below and §§192.703, 192.711(b), 192.713, and 192.717.

## 3 RELIABLE ENGINEERING TESTS AND ANALYSES (§192.485(a))

Reliable engineering tests and analyses demonstrate compliance with a performance standard. Operators may conduct their own tests and analyses; or, they may choose to accept testing and analyses done by manufacturers, trade associations, consultants, or other operators. The engineering tests and analyses should:

(a) Include the following items, as needed, to achieve satisfactory precision.
  (1) Concise and orderly procedures for conducting tests and analyses.
  (2) Listing of equipment needed.
  (3) Descriptions of test specimens.
  (4) Required calculations.

(b) Exhibit sound engineering practices, which may include the following.
  (1) Knowledge and experience relating to the subject area.
  (2) Data evaluation and statistical analysis.
  (3) Assessment of test results to verify an analytical model.
  (4) Application of scientific principles.

# §192.487

## Remedial measures: Distribution lines other than cast iron or ductile iron lines.

*[Effective Date: 01/13/00]*

**(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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999]**

### GUIDE MATERIAL

### 1 Pitting

(a) Where inspection indicates that localized corrosion pitting exists which may result in leakage, or indicates general corrosion exists that does not require replacement under §192.487(a), the operator should consider the following.
  (1) Examining the corrosion history and leak records to see if the additional information from this review warrants replacing a segment of this distribution pipe instead of repair.
  (2) Installing leak clamps over the pits or using other suitable repair methods that will permanently restore the serviceability of the pipeline.

(b) In addition to repairs, the operator should consider the following.
  (1) Cleaning and coating the exposed piping in accordance with §192.461.
  (2) Applying or increasing the level of cathodic protection (CP).
  (3) Installing test wires for monitoring CP.

### 2 RELIABLE ENGINEERING TESTS AND ANALYSES

See guide material under §192.485.

## §192.489

## Remedial measures: Cast iron and ductile iron pipelines.

*[Effective Date: 08/01/71]*

**(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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971]**

### GUIDE MATERIAL

(a) For cast iron pipe, see Guide Material Appendix G-192-18.

(b) For ductile iron, see Guide Material Appendix G-192-18, Section 5.3.

## §192.490

## Direct assessment.

*[Effective Date: 11/25/05]*

**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.**

**[Issued by Amdt. 192-101, 70 FR 61571, Oct. 25, 2005]**

## GUIDE MATERIAL

Direct assessment is a process for managing the effects of external corrosion, internal corrosion, or stress corrosion cracking on pipelines made primarily of steel or iron. This process involves data collection, indirect inspection, direct examination, and evaluation. Operators may use direct assessment not only to find existing corrosion defects, but also to prevent future corrosion problems. See guide material under §§192.925, 192.927, and 192.929.

# §192.491

## Corrosion control records.

*[Effective Date: 07/08/96]*

**(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.**

**[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996]**

## GUIDE MATERIAL

In addition to the specific requirements of §192.491, the data contained in the records or maps used for corrosion control should include the following.

(a) Location of test stations.
(b) Location of rectifiers and groundbeds.
(c) Location of galvanic anodes.
(d) Location of corrosion control facilities, such as insulating flanges or connections, bonds, automatic switches, and diodes.
(e) Readings of pipe-to-soil potential.
(f) Length and location of cathodically protected segments of piping.
(g) Location of unprotected metallic piping.
(h) Date cathodic protection facilities placed in service.

# §192.493

## In-line inspection of pipelines.

*[Effective Date: 07/01/2020]*

**When conducting in-line inspections of pipelines required by this part, an operator must comply with API STD 1163, ANSI/ASNT ILI-PQ, and NACE SP0102, (incorporated by reference, *see* § 192.7). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.**

**[Amdt. 192-125, Oct. 1, 2019]**

## GUIDE MATERIAL

*See Guide Material Appendix G-192-14 for information about in-line inspection of pipelines.*

# SUBPART J
# TEST REQUIREMENTS

## §192.501
## Scope.

*[Effective Date: 11/12/70]*

**This subpart prescribes minimum leak-test and strength-test requirements for pipelines.**

### GUIDE MATERIAL

All newly installed, replaced, or relocated transmission lines, distribution lines, Type A gathering lines, and Type B gathering lines (§192.9(c) and (d)), must be tested in accordance with Subpart J.

## §192.503
## General requirements.

*[Effective Date: 10/01/15]*

**(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 proposed 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.**

**[Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-60, 53 FR 36028, Sept. 16, 1988 with Amdt. 192-60A, 54 FR 5484, Feb. 3, 1989; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]**

## GUIDE MATERIAL

(a) The test procedure should give consideration to such items as the following.
  (1) The method and equipment used.
  (2) The test medium and maximum test pressure.
  (3) The duration of the test.
  (4) The volumetric content of the piping and its location.
  (5) The reason for the pressure test.
    (i) New construction.
    (ii) Pipe replacement.
    (iii) Class location changes.
    (iv) Uprating.
    (v) Integrity assessment.
    (vi) Other as deemed appropriate by the operator.

(b) See §192.619 for test pressure requirements to substantiate the maximum allowable operating pressure for steel and plastic pipelines.

(c) See guide material under §192.517 and Guide Material Appendices G-192-9, G-192-9A, and G-192-10.

# §192.505

## Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

*[Effective Date: 03/12/21]*

**(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 (d) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.**

**(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.**

**[Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69 FR 54591, Sept. 9, 2004; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]**

## GUIDE MATERIAL

## 1 GENERAL

The following preliminary considerations should be noted.

(a) Because of the requirements of §192.611 and the possibility of a change in class location, especially in Class 1 and Class 2 locations, a strength test to at least 90% SMYS is recommended.
(b) A pipeline crossing a railroad, public road, street, or highway might be tested in the same manner and to the same pressure as the pipe on each side of the crossing, recognizing that the pipeline in the crossing might have a different design factor. See §192.111 and the design formula under §192.105.
(c) Fabricated assemblies (e.g., mainline valve assemblies, crossover connections, and river crossing headers) installed in pipelines in Class 1 locations may be tested as required for Class 1 locations (even though §192.111 requires a Class 2 design factor).
(d) Testing against closed valves is not recommended. Testing should include the use of test manifolds. Blinds (e.g., flanges or plates) should be used as necessary to minimize testing against any closed valves. Where valves exist in a test section, they should remain in the open or manufacturer's recommended position during the test. To ensure that air does not enter the gas system, testing with air against a closed valve that is connected to the gas system is not advisable.
(e) A single component with a valid ASME or MSS specification pressure rating may be installed without a pressure test. Rating examples are common designations, such as ASME Class 600. Corresponding temperature limits need to be considered for each pressure rating.
(f) For lateral connections to transmission lines and transmission line replacements, see Note (1) in Guide Material Appendix G-192-9.

## 2 TEST PROCEDURE

The test procedure used should be selected after giving due consideration to items such as the following.

(a) Equipment to be used.
(b) Test medium.*
(c) Environment.
(d) Elevation profile.
(e) Volumetric content of the line.
(f) Test pressure.*
(g) Duration of the test.*
(h) Location of the line.
(i) The effects of temperature changes on the pressure of the test medium.
(j) The reason for the strength test.
    (1) New construction.
    (2) Pipe replacement.
    (3) Class location changes.
    (4) Uprating.
    (5) Integrity assessment.*
    (6) Other as deemed appropriate by the operator.

*See Guide Material Appendices G-192-9 and G-192-9A.

**Example Leak Test Duration for Steel Pipe (hours)**

| Nominal Pipe Size | 2 | 3 | 4 | 6 | 8 | 10 | 12 |
|---|---|---|---|---|---|---|---|
| Schedule | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| ID (in.) | 2.067 | 3.068 | 4.026 | 6.065 | 7.981 | 10.020 | 11.938 |
| Length (ft.) | | | | | | | |
| 50 | 1/4 | 1/4 | 1/4 | 1/2 | 1/2 | 3/4 | 1 1/4 |
| 100 | 1/4 | 1/4 | 1/4 | 3/4 | 1 | 1 1/2 | 2 1/4 |
| 200 | 1/4 | 1/2 | 1/2 | 1 1/4 | 2 | 3 | 4 1/4 |
| 300 | 1/4 | 1/2 | 3/4 | 1 3/4 | 3 | 4 1/2 | 6 1/2 |
| 400 | 1/2 | 3/4 | 1 | 2 1/4 | 4 | 6 | 8 1/2 |
| 500 | 1/2 | 3/4 | 1 1/4 | 2 3/4 | 4 3/4 | 7 1/2 | 10 3/4 |
| 1000 | 3/4 | 1 1/2 | 2 1/2 | 5 1/2 | 9 1/2 | 15 | 21 1/4 |

*Notes:*
1. See 4(d) and (e) of the guide material under §192.513 for an explanation of the calculations used to prepare this table.
2. The detectable pressure drop and detectable leak rate criteria should be based on the operator's design and experience. For this example, the detectable leak rate (*RL*) = 5.0 scf/hr and the detectable pressure drop (*Pd*) = 2 psi.
3. Note that a change in schedule number or wall thickness might affect the calculated duration.
4. Minimum test duration is chosen to be 1/4 hour, and calculated test durations have been rounded up in 1/4-hour increments.
5. For test durations beyond 24 hours, consider testing shorter sections to reduce the test duration.
6. See Guide Material Appendix G-192-9.

**TABLE 192.509i**

# §192.511

## Test requirements for service lines.

*[Effective Date: 07/13/98]*

**(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. (69 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.**

**[Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998]**

**GUIDE MATERIAL**

See 1(b), 3.1, and 4 of the guide material under §192.505; guide material under §§192.509, 192.515 and 192.517; and Guide Material Appendix G-192-10.

## §192.513
## Test requirements for plastic pipelines.

*[Effective Date: 01/22/19]*

**(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% 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 2.5 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 ºF (38 ºC), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.**

**[Amdt. 192-77, 61 FR 27789, June 3, 1996 with Amdt. 192-77 Correction, 61 FR 45905, Aug. 30, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-124.*

### 1 JOINTS

The joints in the plastic piping should be set, cured, or hardened before the test is initiated.

### 2 ODORANT

Odorant in the liquid form may be detrimental to certain kinds of plastic and should not be used to locate leaks in plastic pipelines.

### 3 TEMPERATURE LIMITATIONS

The operator should ensure that piping being tested does not exceed the maximum temperature at which it has been qualified as indicated by the marking on the pipe and fittings. The operator should consider the influence of ambient, test medium, and ground temperatures that can affect the pipe temperature during a test. Sunlight may significantly elevate the pipe temperature, and black plastic pipe can exceed 140 ºF (60 ºC) temperature when exposed to direct sunlight. Some methods used to control or reduce temperatures during testing are as follows.

# SUBPART L
# OPERATIONS

## §192.601
## Scope.

*[Effective Date: 11/12/70]*

**This subpart prescribes minimum requirements for the operation of pipeline facilities.**

### GUIDE MATERIAL

**No guide material necessary.**

## §192.603
## General provisions.

*[Effective Date: 10/25/13]*

**(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.**

**[Amdt. 192-27A, 41 FR 47252, Oct. 28, 1976; Amdt. 192-66, 56 FR 31087, Jul. 9, 1991; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996; Amdt. 192-118, 78 FR 58897, Sept. 25, 2013]**

### GUIDE MATERIAL

*Note*: Although not required, operators of Type B gathering lines should consider establishing their own record retention procedures.

(a) Operators may use any recordkeeping method that produces authentic records. The data constituting these records should be retained in a medium that has a life expectancy at least equal to the specified retention period.

(b) Additional records might be required by state or other federal regulatory agencies.

(c) See guide material under §192.605. Also see Guide Material Appendix G-192-17 for summary of records required by Part 192.

# §192.605

## Procedural manual for operations, maintenance, and emergencies.

*[Effective Date: 02/01/10]*

**(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 operations 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. 192-27A, 41 FR 47252, Oct. 28, 1976; Amdt. 192-59, 53 FR 24942, July 1, 1988 with Amdt. 192-59 Correction, 53 FR 26560, July 13, 1988; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994 with Amdt. 19271A, 60 FR 14379, Mar. 17, 1995; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-112, 74 FR 63310, Dec. 3, 2009]**

## GUIDE MATERIAL

*Note*: Although not required, operators should consider establishing a procedural manual for Type B gathering lines.

## 1 GENERAL

(a) Each procedural manual for operations, maintenance, and emergencies should include a written statement, procedure, or other document addressing each specific requirement of §192.605 that applies to the operator's pipelines. The requirements of §192.605 are included in paragraphs that cover the following topics.
  (1) General items related to the procedural manual (§192.605(a)).
  (2) Maintenance and normal operation of any pipeline; §192.605(b)).
  (3) Abnormal operation of transmission lines, other than those transmission lines operated by distribution operators in connection with their distribution system (§192.605(c)).
  (4) Safety-related condition reports (§192.605(d)).
  (5) Surveillance, emergency response, and accident investigation (§192.605(e)).

  The guide material under this section addresses most of the requirements of §192.605.
(b) The comprehensive manual can consist of multiple binders with relevant sections kept at appropriate locations. Appropriate sections of other documents may be referenced instead of being incorporated, but the referenced documents are to be present at the location to which they apply.
(c) The manual will necessarily vary in length and complexity depending upon the individual operator, its size, locale, policies, and types of equipment in use and the amount of material included in its entirety or cross-referenced, including manufacturers' instructions, where appropriate.
(d) Procedures for only those facilities within the operator's system need be included in the manual.

Therefore, it is not necessary to have a manual for each pipeline.

(e) The required review of the manual should ensure that the operator's current facilities and any deficiencies in the manual are addressed. An operator should consider reviewing its operator qualification (OQ) processes and procedures since changes to the manual may affect the OQ program. More serious deficiencies, possibly identified following an accident, may require immediate correction.

(f) Many sections of the pipeline safety regulations are written using performance language to achieve a desired result, but the method to reach that result is not specified. In such situations, an operator should use a method that is suitable for its individual operations and include it in the manual.

(g) An operator may include material in its procedural manual for operations, maintenance, and emergencies that is not required by the federal or state pipeline safety regulations (e.g., procedures for the use of personal protection equipment, procedures regarding the aesthetic acceptability of paint on aboveground piping). Even though such procedures themselves are supplementary to the procedures required by the pipeline safety regulations, they may be subject to inspection or enforcement by pipeline safety inspection agencies. The operator may consider identifying such procedures as not being part of the manual for operations, maintenance, and emergencies that is required by §192.605.

(h) An operator may define in its manual a process to address situations in which a procedure cannot be followed in its entirety. That process should include the requirement for a written request and approval for a variance from the procedure, the level of authority that can approve a variance, and record-retention requirements. The operator should ensure the effect of the approved variance from the procedure still meets the minimum regulatory requirements.

(j) See guide material under §192.491, 192.603, 192.709, and Guide Material Appendix G-192-17 for additional information on record retention and security.

## 2 MAINTENANCE AND NORMAL OPERATIONS

In addition to those items required to be in the manual under Subparts L and M as they apply to the operator's facilities, other Subparts (e.g., E, F, I, J, and K) may also require written procedures. Additional guide material can be found under individual sections.

*2.1 Control of corrosion.*

Refer to guide material for respective sections of Subpart I.

*2.2 Availability of construction records, maps, and operating history.*

(a) Construction records, maps, and operating history should be comprehensive and current. The construction records, maps, and operating history will depend upon the individual operator, its size and locale, and the types of equipment in use.

(b) The construction records, maps, and operating history should be made available to operating personnel, especially supervisors or those called on to safely operate pipeline facilities or respond to emergencies, or both. Dispatch or gas control personnel should have maps and operating history available.

(c) For transmission facilities, the types of records and data that could be made available are as follows.
  (1) Pipeline system maps, including abandoned and out-of-service facilities.
  (2) Compressor station and other piping drawings (mechanical and major gas piping).
  (3) Maximum allowable operating pressures.
  (4) Inventories of pipe and equipment.
  (5) Pressure and temperature histories.
  (6) Maintenance history.
  (7) Emergency shutdown systems drawings.
  (8) Isolation drawings.
  (9) Purging information.
  (10) Applicable bolt torquing information.
  (11) Operating parameters for engines and equipment.
  (12) Leak history.

(d) For distribution systems, the types of records and data that could be made available are as follows.

(1) Maps showing location of pipe, valves, and other system components.
(2) Maps and records showing pipe specifications, valve type, and operating pressure.
(3) Auxiliary maps and records showing other useful information, including abandoned and out-of-service facilities.

(e) Communications with knowledgeable personnel should be maintained to respond to questions concerning the records, maps, or history if the need arises.

(f) Field identification of valves.
(1) Valve identification criteria should be established.
(2) Each operator should have available sufficiently accurate records (including field location measurements) to readily locate valves and valve covers.
(3) Where valves are located in a valve cluster or in close proximity to valves of other operators, in addition to records and field location measurements, the following are also recommended.
(i) A valve identification system should be developed so that each valve will have a unique set of numbers or letters, or both, which is keyed to the records or mapping system.
(ii) For above ground and vault applications, a readily observable and durable code identifying tag, stamp, or other device should be affixed to the valve.
(iii) For remotely operated and underground valves, a readily observable and durable code identifying tag, stamp or other device should be affixed to the inside wall of the valve box or valve extension unit. It should be affixed so that it will not interfere with the valve operation, and will not be defaced or dislocated by normal operations.

*2.3 Data gathering for incidents.*

(a) The operator should designate personnel to gather data at the incident site and other locations where records are retained.

(b) For verification and telephonic reporting that an incident has occurred on the operator's facility, the following information should be gathered as soon as practicable. See Guide Material Appendix G-191-1 and guide material under §191.5.
(1) Time and date of the incident.
(2) Location and facilities involved.
(3) Number of fatalities and personal injuries necessitating in-patient hospitalization.
(4) Estimates of property damage and gas lost. See guide material under §191.3 and Guide Material Appendix G-191-5.
(5) Type of incident: leak, rupture, other.
(6) Whether there was an explosion.
(7) Whether there was a fire.
(8) Whether there was a curtailment or interruption of service.
(9) Environmental impact.
(10) Apparent cause and responsible party if known.
(11) Component(s) involved and material specification.
(12) Pressure at the time of incident.
(13) Estimated time of repair and return to service.
(14) A 24-hour staffed telephone number.

(c) Procedures should be established for personnel to determine if the event meets the criteria for the Part 191 definition of an "incident" and to make the telephonic report. Alternate personnel should be included in the procedures in case primary personnel are not available. If some of the information is not available, the notification should be made without that information. Any corrections or additional information may be provided later. See guide material under §191.5.

(d) For post-accident drug and alcohol testing, see Part 199 – Drug and Alcohol Testing and OPS Advisory Bulletin ADB-2012-02 (77 FR 10666, Feb. 23, 2012; see Guide Material Appendix G-192-1, Section 2).

(e) For the written Incident Report, see guide material under §192.617 and Guide Material Appendices G-191-2 and G-191-5.

*2.4 Starting up and shutting down a pipeline.*

(a) Starting up any of the following: a newly constructed transmission line, regulated gathering line, distribution main, or another modified pipeline (e.g., an existing transmission line that has a new pressure gradient because of flow reversal, pipeline that has been converted to gas service under §192.14.

(1) For transmission lines, following the test to establish maximum allowable operating pressure (MAOP), the operator and the person in charge of placing the pipeline in service should establish procedures for commissioning the new or modified pipeline and placing it in service. The procedures should include provisions for the following.
   (i) Ensuring that the procedural manual for operations, maintenance, and emergencies addresses the new or modified pipeline.
   (ii) Inspecting the overpressure protection devices required for starting up a new or modified pipeline, including the testing of set pressures and the checking of capacities, if necessary.
   (iii) Determining requirements for purging and notifying public officials. See guide material under §192.751.
   (iv) Establishing communication with field personnel and gas control personnel.
   (v) Controlling the purge flow rate when pressurizing the pipeline and monitoring pressures until normal operation is established.
   (vi) Conducting a follow-up leak survey, if applicable.
   (vii) Updating maps and other pertinent operating records.

(2) For distribution mains, following the test to prove tightness or strength, the operator should establish procedures for commissioning a new main. The procedures should include provisions for the following.
   (i) Ensuring that the procedural manual for operations, maintenance, and emergencies addresses the new main.
   (ii) Tying-in the new system segment.
   (iii) Determining requirements for purging and notifying public officials and residents of purging activity. See guide material under §192.751.
   (iv) Updating maps and other pertinent operating records.

(b) Starting up or reinstating service lines.
The operator should establish procedures for reinstating the service line following the test to prove tightness or strength. The procedures should include provisions for the following.
   (1) Ensuring that the procedural manual for operations, maintenance, and emergencies addresses the new or reinstated services.
   (2) Tying-in new or reinstated service segment.
   (3) Introducing gas into the meter. Also, see 2.4(c) below.
   (4) Updating maps or other pertinent operating records.
   (5) Preventing unauthorized turn-on.

(c) Starting up service to a new customer.
The operator should establish procedures for starting up service to a new customer. The procedures should include provisions for the following.
   (1) Operating the meter or service-line valve.
   (2) Checking the regulator, if present, and the customer meter.
   (3) Where a closed valve is not used at the meter outlet, checking the meter for indications of downstream leakage (e.g., open fuel line).
   (4) Taking appropriate action when downstream leakage is indicated. This may include actions to prevent unauthorized operation of the meter or service-line valve until downstream leakage is eliminated.

(d) Shutting down a pipeline.
See Guide Material Appendix G-192-12.

(e) Abandoning a pipeline after it is shutdown.
See guide material under §192.727.

*2.5 Maintaining compressor stations.*

During normal maintenance activities, the following should be considered and applied where appropriate.

(a) Provisions should be made to prevent gas from entering the compressor cylinders of a reciprocating engine or a compressor case of a centrifugal compressor while work is being performed on the units. These provisions should also include the deactivation of the valve operators.

(b) Provisions should be made to prevent fuel gas from entering the power cylinders of a reciprocating engine or the burner cans of a gas turbine while work is in progress on the unit or equipment driven by the unit.
(c) Provisions should be made to prevent starting air from entering the power cylinders of a reciprocating engine and to prevent starting air or gas from entering any other starting device on an engine or turbine while work is in progress on the unit or equipment driven by the unit. The flywheel of the reciprocating engine should be locked in a stationary position where possible.
(d) Recommended methods for isolating the units from sources of gas or starting air include installation of a blind flange, removal of a portion of the supply piping, or locking a stop valve closed and locking a downstream vent valve open. If a common downstream vent is used, provision should be made to prevent backflow to the units.
(e) Provisions should be made to prevent energizing the electric circuits of a motor driven or motor started compressor unit while work is in progress on the unit or on equipment driven by the unit.
(f) See 2 and 3 of the guide material under §192.147 for bolting information.
(g) Provisions should be made to return the equipment to service in an orderly manner to prevent the uncontrolled release of gas to the atmosphere, or overpressuring an isolated or purged piece of equipment or section of pipe.

*2.6 Starting, operating, and shutting down gas compressor units.*
The procedures for the starting, operating, and shutdown of gas compressor units should be in writing and may be developed from operating experience, direct use of manufacturers' instruction manuals, or a combination of both.

*2.7 Periodically reviewing the work done by operator personnel.*
The operator should designate a timetable to review personnel performance to determine if the normal operating and maintenance procedures found in the manual are effective and adequate. The operator should determine if deficiencies exist in the procedures. If applicable, modification of procedures should be accomplished as soon as possible. Documentation should be maintained for all procedure modifications and retraining of personnel.

*2.8 Taking precautions in excavated trenches to protect personnel.*
Personnel working in or near a trench should be aware of the potential for an oxygen-deficient environment and of potential dangers from accumulations of gas or vapor, particularly those associated with liquid petroleum gases. When determining the likelihood of gas or vapors presenting such a hazard to personnel, the operator should consider the depth and configuration of the trench, the product transported, and the diameter, pressure, type of piping material, condition, and configuration of the pipeline facilities. Although natural gas is lighter than air and non-toxic, some natural gas pipelines contain constituents such as hydrogen sulfide, heavier-than-air hydrocarbons, and hydrocarbon liquids that may present a hazard to personnel working in or near the trench. The operator should establish criteria for what constitutes a hazardous condition, taking into consideration the LEL of the gas involved. Escaping gas may present an added hazard because of the displacement of oxygen. An atmosphere containing less than 19.5% oxygen should be considered oxygen-deficient for respiration. When it is necessary for personnel to enter an excavated trench where hazards could reasonably be expected, the operator should consider taking the following actions, as appropriate.
(a) Confirming that atmospheric monitoring devices, rescue equipment, and breathing apparatus are in working order prior to each use.
(b) Checking the atmosphere in the excavated trench.
(c) Establishing a means of exiting the trench.
(d) Reviewing the rescue plan.
(e) Placing a safety observer outside the trench to monitor the atmosphere inside the trench and to be available to assist in use of rescue equipment, operation of a fire extinguisher, or otherwise assist in a rescue.
(f) Minimizing sources of ignition in and around the trench. See guide material under §192.751.
(g) Taking actions to reduce the accumulation of gas or vapors, such as:

(1) Isolating the gas facility by closing valves, squeezing off, bagging off, or using stoppers.
(2) Reducing pressure in the facility.
(3) Ventilating the work area.

(h) Requiring the use of flame-retardant clothing, respiratory protection, or a rescue harness and line, as appropriate. The operator's written procedures should describe activities and situations where use of these items is required.

*2.9 Responding promptly to a report of a gas odor inside or near a building.*
See §192.605(b)(11), which requires procedures in either the procedural manual or its related emergency plan. See 1.1 and 1.3(a) of the guide material under §192.615 for related information.

*2.10 Control room management procedures.*
See guide material under §192.631.

**3 ABNORMAL OPERATION OF TRANSMISSION LINES**

*3.1 General.*

*(a)* The abnormal operation requirements in §192.605(c) do not apply to distribution operators that are operating transmission lines in connection with their distribution system (§192.605(c)(5)).

(b) An abnormal operation is a non-emergency event on a gas transmission facility that occurs when the operating design limits have been exceeded due to a change in pressure, flow rate, or temperature that is outside the normal limits. When an abnormal operation occurs, it does not pose an immediate threat to life or property, but could if not promptly corrected. Where applicable, the actions to be taken by the transmission operator in each situation should incorporate the current procedures. The procedures should be specific enough to ensure uniformity of action relative to the situation, such as those referenced above, while allowing sufficient flexibility to consider the particular details, material, equipment, and configurations involved.

*3.2 Considerations for abnormal operations.*
When developing response procedures for abnormal operations, the transmission operator should consider the following.

(a) Type of event. See list under §192.605(c)(1).
(b) Proximity of the event to the public.
(c) Potential for the event to become an emergency situation if not immediately corrected.
(d) Effect of the event on the pipeline system.
(e) Notification of appropriate operator personnel regarding the abnormal operation.
(f) Documentation of the response actions taken.
(g) If the event is an increase in pressure outside normal operating limits, the potential for MAOP plus allowable buildup to be exceeded. See 4.4(f) below and (d) of the guide material under §191.23.
(h) Determine if a failure investigation of equipment is needed in accordance with the requirements of §192.617.

*3.3 Preventing recurrence of abnormal operation.*
Once the event has been investigated, and normal or safe operations have been restored, the operator should determine what measures can be taken to prevent the cause of the event from recurring. The operator should also consider whether these measures should be implemented elsewhere in the transmission system to avoid similar occurrences of abnormal operation.

*3.4 Follow-up monitoring.*

The extent of follow-up monitoring should be based on the nature of the event and the probability that the cause of the event could recur. The abnormal operation is considered corrected when an operator determines, at the end of the monitoring period, that the pipeline facility has maintained operations within its operating design limits and is capable of safely operating up to its MAOP.

*3.5 Follow-up actions to consider.*

(a) Notify field operations and maintenance personnel to be alert to signs of leakage or damage to pipeline facilities.
(b) Notify control room personnel, so they can more closely monitor facilities.
(c) Conduct and document right-of-way patrol of the affected pipeline segment.
(d) Conduct and document leak survey of the affected pipeline segment.
(e) Conduct and document inspection of overpressure protection devices for signs of activation. Determine if the devices activated as expected and at the correct pressures.
(f) Determine probable cause or conduct failure analysis; share results with appropriate personnel. For guidance on performing a failure investigation, see guide material under §192.617.
(g) Ensure integrity management personnel are informed so this event and associated data can be considered in future risk analyses.
(h) Review procedural manual, operator qualification program, control room management procedures, and other written procedures for any needed revisions.

*3.6 Review of response activities.*

Response activities should be reviewed based on the extent of the abnormal operation. The review should consider the actions taken and whether the procedures followed were adequate for the given situation or should be revised to provide more specificity or more flexibility.

**4 POTENTIAL SAFETY-RELATED CONDITIONS, ANALYSIS, AND ACTIONS**

*4.1 Potential safety-related conditions.*

Personnel who perform O&M activities should recognize the following anomalies as potential safety-related conditions that may be subject to the reporting requirements of §191.23.

*Note:* Reporting requirements for (a), (b), and (d) below apply to a pipeline that operates at 20% or more of SMYS.

(a) General corrosion that has reduced the pipe wall thickness to less than that required for the MAOP.
(b) Localized corrosion pitting which has progressed to a degree where leakage might result.
(c) Unintended movement or abnormal loading by environmental causes (e.g., earthquake, landslide, subsidence, flood) that impairs the serviceability of a pipeline segment.
(d) Material defects, such as those caused in the manufacturing process, or physical damages that impair the serviceability of a pipeline segment. Sound engineering criteria should be used to determine if an observed condition involving a material defect or physical damage impairs serviceability.
(e) Malfunctions or operating errors that cause the pressure of a pipeline to rise above its MAOP plus the buildup allowed for the operation of pressure limiting or control devices
(f) Pipeline leaks that constitute the need for immediate corrective action to protect the public or property. Examples include leaks occurring in residential or commercial areas in conjunction with a natural disaster; leaks where a flammable vapor is detected inside a building; and leaks that involve response by police or fire departments. While venting is done to mitigate an unsafe condition, it does not remove the unsafe condition.
(g) Other known anomalies or events that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator) for purposes other than abandonment, a 20% or more reduction in operating pressures or shutdown of operation of the affected pipeline segment.

Each operator should establish a training program that will provide operating and maintenance personnel with a basic understanding of each element of the procedural manual for operations, maintenance, and emergencies appropriate to the job assignment. A significant change in operating conditions, such as flow reversal or conversion to gas service, might warrant additional training. See 2.7 above regarding periodic reviews, procedure modifications, and retraining of personnel.

*6.2 Operations and maintenance tasks.*
See Subpart N.

*6.3 Emergency response procedures.*
Each operator is required by §192.615(b)(2) to train the appropriate operating personnel to ensure that they are knowledgeable of the emergency procedures. See 2 of the guide material under §192.615.

## 7 OTHER CONSIDERATIONS

*7.1 "Work authorization" programs.*
Operators should consider including written procedures in their procedural manual for operations, maintenance, and emergencies to protect maintenance workers from the unexpected movement or release of energy when working on electrical, pressurized fluid, or mechanical systems where the inadvertent actuation or release of energy could be dangerous. The procedures commonly used to protect maintenance personnel include "lockout," "tagout," "blocking," and "work authorization" programs. Equipment that should be considered includes compressors, filters, scrubbers, launchers, heat exchangers, and powered valve actuators.

*7.2 Operator's use of powered equipment.*
Before using powered equipment for making an excavation, the operator should consider the following.
(a) The use of pertinent maps, other records, or other means to locate the operator's facilities.
(b) Verifying that all other operators of underground facilities in the area have been notified of the pending excavation and have responded by marking their facilities.
(c) Determining safe distances to be maintained between the digging end of the powered equipment and underground facilities.
(d) The use of qualified personnel as necessary. See OPS Advisory Bulletin ADB-06-01 (71 FR 2613, Jan. 17, 2006; reference Guide Material Appendix G-192-1, Section 2).

*7.3 Verification of established MAOP*
(a) Operators should consider including written procedures in their manual for operations, maintenance, and emergencies that address the actions to be taken after records or materials are discovered that may call into question a pipeline's established MAOP. These written procedures should address the following, as applicable.
   (1) Date the pipeline segment became regulated as outlined in §192.13, and how to address unknown or newly discovered records, or record discrepancies.

   (2) Review of maintenance and construction activities subsequent to the original pressure test to verify that any repairs, relocations, or replacements meet the MAOP requirements and have the proper test and material documentation.
   (3) Discovery of a pressure test record used to establish the pipeline's current MAOP that has a lower test value, a shorter test duration, or other test record that does not meet the requirements for a valid pressure test as outlined in Subpart J.
   (4) Review of §§192.619, 192.621, 192.623 and 192.611 to determine if MAOP calculations are still valid.
   (5) Options to use field verification for a record indicating an unknown strength or rating, or a pressure rating less than the pipeline's established MAOP.
   (6) Consideration of an appropriate operating pressure reduction or restriction.

(7) Coordination with operator's gas control personnel for planning potential operating pressure changes that could affect control room operations.

(b) If the MAOP verification indicates changes to MAOP are necessary, the operator should consider the following actions.
   (1) Assessing the impact to the pipeline system.
   (2) Identifying a remediation strategy for addressing deficiencies.
   (3) Revising the operator's pipeline records, which may include:
      (i) manual for operations, maintenance, and emergencies.
      (ii) gas control records.
      (iii) gas control alarms.
      (iv) GIS.
      (v) electronic databases.
      (vi) other records and documents where the operator may record pipeline MAOP data.
   (4) Communicating the change to the appropriate operator personnel.
   (5) Reviewing and revising overpressure protection requirements.
   (6) Identifying potential reporting requirements.

(c) If an operator suspects that liquid hydrocarbons might be present in PE pipe, either from the surrounding soil or from liquid in the gas stream, they should perform a heat fusion melt pattern test on the pipe. If the operator sees bubbles in the PE pipe melt pattern or the fusion bead has a rough, pockmarked surface appearance, this might be an indication that liquid hydrocarbons have permeated the outer pipe wall. The operator should follow their procedures for repair of pipe with an incomplete heat fusion melt pattern. If the operator suspects that liquid hydrocarbons have penetrated the PE pipe wall, see the guide material under §192.121 regarding the effect of liquid hydrocarbons on design pressure. The operator might need to reduce the MAOP established under §192.619 based on the presence of liquid hydrocarbons.

(d) Operators who have determined that liquid hydrocarbons are present in PE pipes should determine the source of liquid hydrocarbons or gas condensates. If a source can be identified and eliminated, the operator should take appropriate steps to eliminate the liquid hydrocarbons. It is possible for the hydrocarbons to migrate out of the pipe wall over time if the source of contamination is eliminated. If subsequent melt pattern tests no longer have bubbles, the liquid hydrocarbons are no longer present in the PE pipe and the pipe's design pressure no longer requires adjustment due to the liquid hydrocarbons.

## §192.607

### Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

*[Effective Date: 07/01/2020]*

**(a) *Applicability*. Wherever required by this part, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this section.**

**(b) *Documentation of material properties and attributes*. Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at § 192.624(c)(3) or the fracture mechanics requirements at § 192.712 must be maintained for the life of the pipeline.**

**(c) *Verification of material properties and attributes*. If an operator does not have traceable,**

**verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities; Anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:**

**(1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined in a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.**

**(2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.**

**(3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.**

**(4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.**

**(5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.**

**(d) *Special requirements for nondestructive Methods*. Procedures developed in accordance with paragraph (c) of this section for verification of material properties and attributes using nondestructive methods must:**

**(1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage.**

**(2) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and**

**(3) Use test equipment that has been properly calibrated for comparable test materials prior to usage.**

**(e) *Sampling multiples segments of pipe*. To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:**

**(1) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of the defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.**

**(2) For each population defined according to paragraph (e)(1) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, in situ evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavations activities pursuant to § 192.614, until completion of the lesser of the following:**

**(i) One excavation per mile rounded up to the nearest whole number; or**

**(ii) 150 excavations if the population is more 150 miles.**

**(3) Prior tests conducted for a single excavation according to the requirements of paragraph (c) of this section may be counted as one sample under the sampling requirements of this paragraph (e).**

**(4) If the test results identify line pipe with properties that re not consistent with available information or existing expectations or assume properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with § 192.18.**

**(5) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (e)(2) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.**

**(f) *Components.* For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (c) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5(incorporated by reference, see § 192.7)).**

**(1) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.**

**(2) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:**

**(i) Larger than 2 inches in nominal outside diameter,**

**(ii) Material grades of 42,000 psi (Grade X-42) or greater, or**

**(iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.**

**(3) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.**

**(g) *Uprating.* The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assume yield strength of 24,000 pisi in accordance with § 192.107(b)(2).**

**[Amdt. 192-125, Oct. 1, 2019]**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-125.*

# §192.609

## Change in class location: Required study.

*[Effective Date: 11/12/70]*

**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.**

### GUIDE MATERIAL

This section applies to transmission lines and Type A gathering lines operating above 40 percent SMYS.

# §192.610

## Change in class location: Change in valve spacing.

*[Effective Date: 10/05/2022]*

**(a) If a class location change on a transmission pipeline occurs after September 27 2022, and results in pipe replacement, of 2 or more miles, in the aggregate, within any 5 contiguous miles within a 24-month period, to meet the maximum allowable operating pressure (MAOP) requirements in §§192.611, 192.619, or 192.620, then the requirements in §§192.179, 192.634, 192.636, as applicable, apply to the new class location, and the operator must install valves, including rupture-mitigation valves (RMV) or alternative equivalent technologies, as necessary, to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with the timing requirement in §192.611(d) for compliance after a class location change.**

**(b) If a class location change occurs after September 27 2022 and results in pipe replacement of less than 2 miles within 5 contiguous miles during a 24-month period, to meet the MAOP requirements in §§192.611, 192.619, or 192.620, then within 24 months of the class location change, in accordance with § 192.611(d), the operator must either:**

**(1) Comply with the valve spacing requirements of §192.179(a) for the replaced pipeline segment; or**

**(2) Install or use existing RMVs or alternative equivalent technologies so that the entirety of the replaced pipeline segments are between at least two RMVs or alternative equivalent technologies. The distance between RMVs and alternative equivalent technologies for the replaced segment must**

**not exceed 20 miles. The RMVs and alternative equivalent technologies must comply with the applicable requirements of §192.636.**

**(c) The provisions of paragraph (b) of this section do not apply to pipeline replacements that amount to less than 1,000 feet within any 1 contiguous mile during any 24-month period.**

**[Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

# §192.611

## Change in class location: Confirmation or revision of maximum allowable operating pressure.

*[Effective Date: 12/22/08]*

**(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. 192-5, 36 FR 18194, Sept. 10, 1971; Amdt. 192-53, 51 FR 34987, Oct. 1, 1986; Amdt. 192-63, 54 FR 24173, June 6, 1989 with Amdt. 192-63 Correction, 54 FR 25716, June 19, 1989; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-94, 69 FR 32886, June 14, 2004; RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; Eff. date stayed by 73 FR 72737, Dec. 1, 2008]**

## GUIDE MATERIAL

This section applies to transmission lines and Type A gathering lines operating above 40 percent SMYS.

### SPECIAL PERMIT (WAIVER) FOR CLASS LOCATION

*Note:* A "special permit" was previously referred to as a "waiver" by PHMSA-OPS. State terminology may differ (e.g., waiver, variance).

(a) When the MAOP of a pipeline is not commensurate with the new class location, PHMSA-OPS will consider special permit (waiver) requests under §190.341 to implement alternative measures to provide an equivalent or greater level of safety, provided that the terms and conditions of the special permit are met. For additional guidance on PHMSA expectations for content of wavier requests and eligible pipelines, see the OPS Notice for "Development of Class Location Change Waiver Criteria" (69 FR 38948, June 29, 2004; reference Guide Material Appendix G-192-1, Section 2).

(b) Operators of interstate pipelines are required to submit special permit (waiver) requests to PHMSA-OPS. Operators of intrastate pipelines are required to submit requests to the state pipeline regulatory authority or to PHMSA-OPS if there is no state pipeline regulatory authority.

# §192.612

## Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.

*[Effective Date: 09/09/04]*

**(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.**

**[Issued by Amdt. 192-67, 56 FR 63764, Dec. 5, 1991; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-98, 69 FR 48400, Aug. 10, 2004]**

## GUIDE MATERIAL

## 1 IDENTIFICATION

*1.1 Criteria for identifying pipelines.*

Operators are required to identify their pipelines located in the Gulf of Mexico and its inlets, where the water is less than 15 feet deep as measured from mean low water. Rivers, tidal marshes, lakes, and canals are excluded. Operators may determine where the water depth of the Gulf of Mexico and its inlets is 15 feet or less by referencing USGS maps or depth charts, USCG water depth maps or tables, or their own construction and maintenance records.

*1.2 Assessing risk of identified pipelines.*

Operators should assess the risk of such pipelines being exposed or being a hazard to navigation by considering the following.

(a) Types of vessels navigating the water body.
(b) Traffic density of vessels navigating the water body.
(c) Possible effects that hurricanes or other significant natural occurrences might have on pipeline depth of cover.
(d) History of pipeline damage from navigating vessels.
(e) Geological restrictions to navigation over the pipeline, such as the proximity of a land mass or the presence of water much shallower than 15 feet.
(f) Results of previous underwater inspections of the pipeline.
(g) Changing conditions of the sea floor, such as scouring, shifting, mudslides, collapsing, and silting.

## 2 INSPECTION

*2.1 Inspection frequencies and prioritization.*

(a) Operators may use the information obtained in 1.2 above to establish the frequency for inspecting each pipeline.
(b) Operators should prioritize the order in which the pipelines may be inspected and inspect those of perceived higher risk first, and possibly more frequently.
(c) Pipelines that operators determine are at risk of becoming a hazard to navigation or becoming exposed should be inspected more often, but operators should establish intervals for repeating inspections based upon the risks.

*2.2 Inspection methods.*

Operators may employ any suitable method, or a combination of methods, for underwater pipeline inspection based upon conditions required by a pipeline's specific environment. Operators should consider the following methods.

(a) Divers.
(b) Ultrasound or sidescan sonar.
(c) Remotely operated underwater inspection devices or vehicles (e.g., ROVs).
(d) Photography.
(e) Probing.

## 3 REPORTING (§192.612(c)(1))

In addition to the reporting requirements of §192.612(c)(1), an operator should also consider including the following.
(a) Latitude and longitude of the pipeline end points.
(b) Offshore area name.
(c) Offshore block number.
(d) Name of water body.
(e) Name of parish or county.
(f) Other pertinent information.

## 4 REMEDIAL ACTION

If an operator is unable to meet the deadline for remediation, the required notification to OPS should be in writing.

# §192.613

## Continuing surveillance.

*[Effective Date: 11/12/70]*

**(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).**

## GUIDE MATERIAL

*Note*: Although not required, operators should consider including Type B gathering lines in continuing surveillance efforts.

## 1 GENERAL

Continuing surveillance should be conducted to identify any pipeline facilities experiencing abnormal or unusual operating and maintenance conditions. This may be accomplished by the following.
(a) Periodic visual inspection of pipeline facilities to identify items such as the following.
    (1) Changes in population densities.
    (2) Effects of changes in topography.
    (3) Effects of exposure or movement.
    (4) Effects of encroachments.
    (5) Specific circumstances relating to patrolling and leakage. See guide material under §§192.705,

192.706, 192.721, and 192.723.

(6) Potential for, or evidence of:
   (i) Excavation activity.
   *Note:* If evidence of an excavation is found near a transmission pipeline covered segment, the location must be examined in accordance with §192.935(b)(1)(iv).
   (ii) Tampering, vandalism, or damage.
   (iii) Flooding. See 6 below
   (iv) Mining activity. See Guide Material Appendix G-192-13.
   (v) Soil or water accumulation in vaults or pits.
   (vi) Gas migration through air intakes into buildings from vaults and pits.
   (vii) Excessive snow and ice build-up on aboveground facilities (e.g., meter sets, pressure control equipment, heaters) that could affect their function.

(b) Periodic review and analysis of records, such as the following.
   (1) Patrols.
   (2) Leak surveys.
   (3) Valve inspections.
   (4) Vault inspections.
   (5) Pressure regulating, relieving, and limiting equipment inspections.
   (6) Corrosion control inspections.
   (7) Facility failure investigations.

Anomalies discovered should be evaluated, and those determined to present potential safety concerns should be scheduled for remediation and communicated to appropriate integrity management personnel.

## 2 CAST IRON PIPELINES

For cast iron pipelines, see Guide Material Appendix G-192-18.

## 3 PE PIPELINES

*3.1 Brittle-like cracking.*

(a) Some PE materials manufactured before 1982 have a lower resistance to the effects of induced stresses and are subject to brittle-like cracking under certain in-service conditions (e.g., rock impingement, squeeze-offs, severe bending moments). Brittle-like cracking is characterized by a part-through crack initiating in the pipe wall followed by slow crack growth causing failure. These failures result in a tight slit-like opening and a gas leak. This older generation of PE may have leak-free performance for a number of years before brittle-like cracks occur. An increase in the occurrence of leaks is typically the first indication of a brittle-like cracking problem.

(b) PE materials that are most known for this failure mode include the following.
   (1) Century Utility Products, Inc. products.
   (2) Low-ductile inner wall PE 2306 "Aldyl A" pipe manufactured by DuPont Company during 1970 through 1972, generally NPS 1¼ to NPS 4. To determine if the "Aldyl A" pipe has low-ductile inner wall, see 3(f) below.
   (3) PE gas pipe designated PE 3306.
   (4) DuPont PE tapping tees with DuPont Delrin® polyacetal (homopolymer) inserts (see 3(g) below).
   (5) Plexco PE service tees with Celanese Celcon® polyacetal (copolymer) caps (see 3(h) below).

(c) Conditions that may cause these types of materials to fail prematurely include the following.
   (1) Inadequate support and backfill during installation.
   (2) Tree root or rock impingement.
   (3) Shear and bending stresses due to differential settlement resulting from factors such as:
      (i) Excavation in close proximity to PE piping.
      (ii) Directional drilling in close proximity to PE piping.
      (iii) Frost heave.
   (4) Bending stresses due to pipe installations with bends exceeding recommended practices.

(5) Stresses where the pipe has been squeezed off.

(d) Each operator that has these older PE pipelines should consider the following practices.
  (1) Review system records to determine if any known susceptible materials have been installed in the system.
  (2) Perform more frequent inspection and leak surveys on systems that have exhibited brittle-like cracking failures of known susceptible materials.
  (3) Collect failure samples of PE piping exhibiting brittle-like cracking.
  (4) Record the print line from any piping that has been involved in a failure. The print line information can be used to identify the resin, manufacturer, and year of manufacture for plastic piping.
  (5) For systems where there is no record of the piping material, consider recording print line data when piping is excavated for other reasons. Recording the print line data can aid in establishing the type and extent of PE piping used in the system.
  (6) Develop procedures for taking appropriate action, including pipe replacement, to mitigate potential pipe failures.
  (7) Use a consistent record format to collect data on system failures. It is recommended that operators use a standard industry form developed for gathering data on plastic pipe failures to help trend and evaluate the extent of plastic pipe performance problems. For information about such form, visit the AGA website at www.aga.org under "Operations and Engineering/Plastic Piping Data Project."

(e) For those pipeline systems that contain products manufactured by Century Utility Products, Inc. between 1970 and 1973, the systems should be monitored and necessary replacements made for system integrity and public safety.

(f) An operator can determine if the PE 2306 "Aldyl A" piping manufactured by DuPont Company during 1970 through 1972 has low-ductile inner wall by using the following procedure.
  (1) Cut a ½-inch ring from the pipe.
  (2) Cut the ring at one point.
  (3) Reverse bend the ring, exposing the inner surface of the pipe.
  (4) Bend back the ring until the outer surfaces of the pipe (or cut ends) touch.
  (5) Cracking on the inner surface of the ring in the bend area indicates low-ductile inner wall.

(g) DuPont PE tapping tees with Delrin polyacetal inserts were installed in gas systems from the late 1960s to the early 1980s and should be replaced as they are discovered. These can be distinguished by a black cap with male threads and a tan PE body.

(h) Plexco PE service tees with Celcon polyacetal caps were installed in gas systems prior to 1996. Caps that show marks from the use of a tool (e.g., pipe wrench or Channellock®-type pliers) on the cap should be replaced.

(i) References concerning brittle-like cracking in PE materials include the following.
  (1) NTSB Reports
    (i) PAB-98-02 available at www.ntsb.gov/investigations/AccidentReports/Pages/pipeline.aspx
    (ii) SIR-98-01 available at www.ntsb.gov/safety/safety-studies/Pages/SafetyStudies.aspx
  (2) OPS Advisory Bulletins (see Guide Material Appendix G-192-1, Section 2) as follows.
    (i) ADB-99-01 (64 FR 12211, Mar. 11, 1999).
    (ii) ADB-99-02 (64 FR 12212, Mar. 11, 1999).
    (iii) ADB-02-07 (67 FR 70806, Nov. 26, 2002 with Correction, 67 FR 72027, Dec. 3, 2002).
    (iv) ADB-07-02 (72 FR 51301, Sept. 6, 2007 with Correction, 73 FR 11192, Feb. 29, 2008).
  (3) "Correlating Aldyl 'A' and Century PE Pipe Rate Process Method Projections with Actual Field Performance," E.F. Palermo, Ph.D., Plastics Pipes XII Conference, April 2004, available at www.aga.org/GPTC.

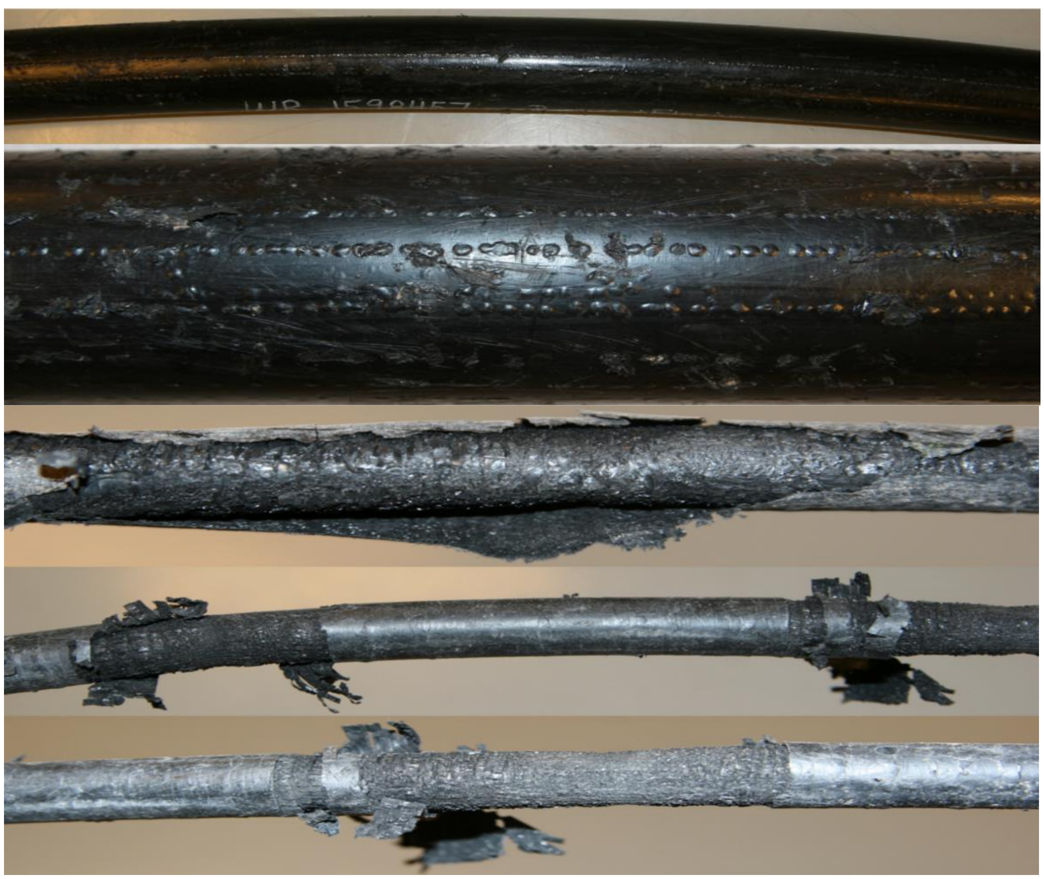
*3.2 Degradation due to thermal oxidation.*

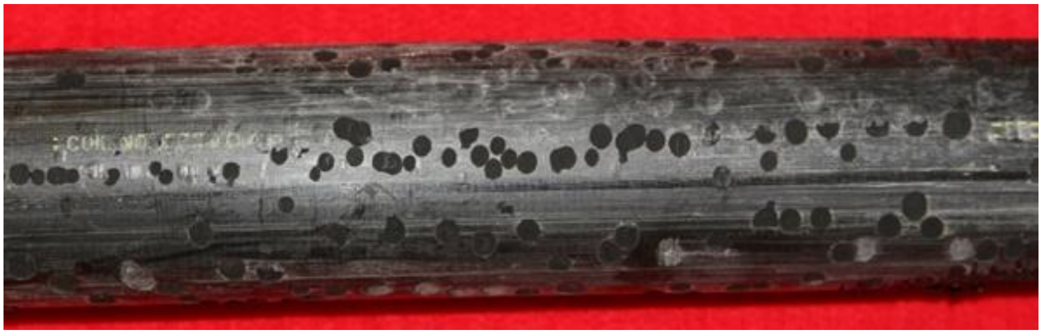
Driscopipe® 7000 and 8000 high-density (HD) PE pipe exposed to prolonged elevated temperatures might degrade as a result of thermal oxidation. The mechanism for this oxidation appears to be the depletion of the thermal stabilizer, which has been shown to occur over time in regions of high ambient temperatures. There is no evidence that other PE piping products are similarly affected. Driscopipe®

7000 and 8000 HDPE pipes were produced from pipe materials that contained specific and unique additives.
(a) Based on laboratory testing and observed field performance, the regions of the U.S. that have the highest ambient temperature conditions are of particular concern.
(b) The potential for thermal oxidation of Dricopipe® 7000 and 8000 HDPE pipe increases as a function of elevated pipe temperature and exposure time. Segments of pipe that are not actively flowing gas such as service lines; CTS services (typically service lines) have experienced more leakage than IPS sizes (typically mains).
(c) Thermal oxidation might present as external degradation on the outside surface of the pipe or internal degradation on the inside surface of the pipe, or both.

(1) External degradation might be observed through visual inspection of the pipe or detected audibly by squeezing of the pipe (see 3.2(f) below). External degradation does not normally result in a loss of integrity or leakage, provided the material is still sound below the degraded surface.

(2) External degradation might pose operational concerns for the operator as joining of the pipe might require special fittings to avoid creating a source of leakage with externally sealing fittings. Operators are encouraged to consider externally degraded pipe segments for replacement. Another consideration is decreasing the maximum operating pressure of the pipe to account for wall loss attributed to external degradation.



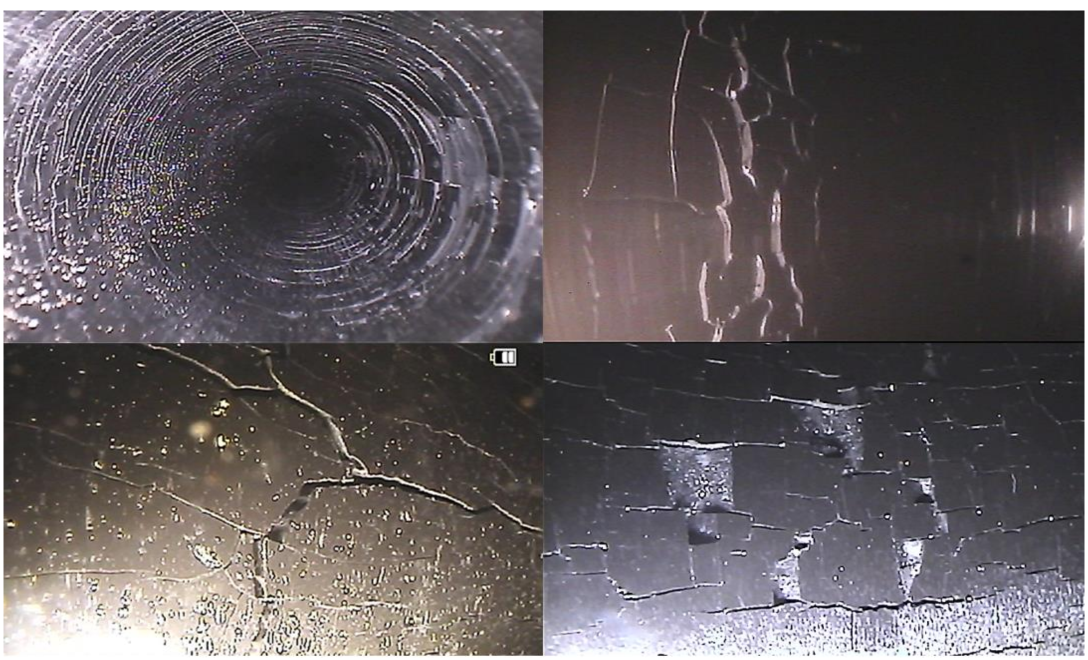


***Note:* Photographs of pipes provided with permission of the operator.**

(d) Internal degradation is not observable unless the pipe is cut apart and the internal surface exposed. Internal degradation might appear as a rough slit crack, spider webbing, or mud cracking on the internal surface of the pipe. Depending on the extent of the degradation, leakage of the pipe might occur. The leak might be visible on the external surface by a slit crack or pinholes bubbling when soap tested. The following factors increase the likelihood of internal degradation for segments of pipe that are not actively flowing gas such as service lines (CTS sizes have experienced more leakage than IPS sizes) that do not supply gas to a customer:

(1) Increased average and maximum ambient temperatures;
(2) Increased gas temperature;
(3) Soil thermal diffusivity;
(4) Decreased burial depth;
(5) Ground covers that hold heat, such as concrete and asphalt; and
(6) Decreased or diminished gas flow (loss of cooling in the pipe).

Internal degradation presents a higher risk of leakage compared to external degradation. Also, CTS sizes have experienced more leakage than IPS sizes. If discovered, additional or accelerated actions for the internal degradation might include accelerated leak survey, replacement, or abandonment of inactive segments of Driscopipe® 7000 and 8000 HDPE pipe.



***Note:* Photographs of pipes provided with permission of the operator.**

(e) Each operator that has Driscopipe® 7000 or 8000 HDPE pipe as part of their system should consider

**(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.**

**[Issued by Amdt. 192-40, 47 FR 13818, Apr. 1, 1982; Amdt. 192-57, 52 FR 32798, Aug. 31, 1987; Amdt. 192-73, 60 FR 14646, Mar. 20, 1995; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-82, 62 FR 61695, Nov. 19, 1997; Amdt. 192-84, 63 FR 7721, Feb. 17, 1998 with Amdt. 192-84 Removal, 63 FR 38757, July 20, 1998 and Amdt. 192-84 Correction, 63 FR 38758, July 20, 1998]**

## GUIDE MATERIAL

*Note:* Section 192.616 requires most operators, including Type A and Type B gathering line operators, to develop and implement a written continuing public education program that follows the guidance provided in API RP 1162 for identifying and notifying excavators and the affected public about damage prevention. These identification and notification activities are required by §192.614. Guide material for these program activities is provided in 2.3, 2.4, and 2.5 below.

## 1 SCOPE

This guide material covers damage prevention programs for buried pipelines, including Type A and Type B gathering lines. The guide material excludes pipelines specified under §192.614(d) and (e) that are exempt from the requirement for a written damage prevention program. For considerations to minimize damage by outside forces, see Guide Material Appendix G-192-13.

Some activities performed as requirements for damage prevention may also be used to satisfy similar program requirements under §§192.615, 192.616, 192.620(d)(2), and 192.935.

## 2 WRITTEN PROGRAM

Written procedures, when required, should state the purpose and objectives of the damage prevention program and provide methods to achieve them. For program content, operators should review applicable state and local one-call requirements. A reference for state requirements is the One Call Systems International (OCSI) Resource Guide, which provides a summary of the damage prevention laws in each state, found at https://commongroundalliance.com/map. In addition, operators should review the Common Ground Alliance's "Best Practices" Guide, found at https://commongroundalliance.com/best-practices-guide. The procedures should include the following.

2.1 *Definition of excavation activities*.

In defining excavation activities to be covered by the damage prevention program, the operator should review the definition in §192.614(a) and applicable state and local requirements. Additional definitions for "excavation" and "excavator" can be found in 49 CFR §196.3.

2.2 *One-call systems*.

(a) A one-call system may exist that does not meet the qualification requirements of §192.614(b)(1) or (b)(2). If the operator participates in a non-qualified one-call system, either because a qualified one-call system does not cover the area or for any other reason, the operator should consider working with that one-call system to make it qualified.

(b) If a one-call system covering the operator's facilities does not exist, the operator should consider establishing a qualified one-call system with other underground facility operators.

(c) The operator is cautioned that satisfying the requirements of §192.614 may require more than participation in a one-call system. The operator should evaluate the services being provided by the one-call system to determine what additional measures may need to be taken to satisfy the requirements of §192.614.

2.3 *Identifying entities to be informed of the program*.

(a) Excavators. The sources listed below may be helpful when preparing the list of entities engaged in excavation activities. The procedure should provide for a periodic review of the list to ensure that it is current.
- (1) One-call center.
- (2) Contractor licensing agencies.
- (3) Contractor associations.
- (4) Local utilities.
- (5) Pipeline companies.
- (6) Insurance carriers.
- (7) State, county, and local road maintenance offices.
- (8) Operator records that could provide information on excavation activities, such as pipeline patrols.
- (9) Farmers, adjacent landowners, and industrial complex operators (e.g., asphalt plants, cement plants, mines, and quarries).
- (10) State, county, and local permitting agencies.
- (11) Outside consultants, such as direct mail contractors or public relations firms.
- (12) Telephone yellow page directory and electronic database listings, such as the following.
  - (i) Excavating and earth moving contractors.
  - (ii) Construction contractors.
  - (iii) Blasting contractors.
  - (iv) Well drilling and boring contractors.
  - (v) Landscaping contractors.
  - (vi) Land leveling and subsoiling contractors.
  - (vii) Dredging companies.
  - (viii) Plumbers.
  - (ix) Fence erectors.
  - (x) Power line contractors.

(b) The public. The public in the vicinity of the pipeline can be identified by land and tax records, census (Tiger) files, operator and pipeline rights-of-way data, or field survey. The general public should be informed for distribution systems. For transmission systems, the public may include the following.
- (1) Residents living on, or adjacent to, the pipeline rights-of-way.
- (2) Businesses adjacent to the pipeline rights-of-way.
- (3) Easement holders.
- (4) Utility companies.
- (5) Homeowner organizations.
- (6) Other pipeline companies within the area.

(7) Church groups.
(8) Schools.
(9) One-call centers.

(c) Government organizations. The following government organizations should be considered for receiving program information.
(1) Federal, state, county, and municipal governments.
(2) Local fire, police, and sheriff departments.
(3) Emergency management agencies.
(4) Building departments.
(5) Highway departments.
(6) State land departments.

(d) Railroads. Railroad operators whose rights-of-way contain pipeline should be identified. Railroads operating within the area of the pipeline operator may be identified through the Federal Railroad Administration.

2.4 *Methods of informing entities of the program*.
One-call centers and outside consultants, such as direct mail contractors or public relation firms, may be considered to assist the operator with distribution of program materials and information.

(a) Excavators. Actual notification is required to persons who normally engage in excavation activities in the area in which the pipeline is located. Actual notification means providing information directly to the excavator. Methods of providing actual notification should include one or more of the following to target the excavators identified under 2.3 of this section.
(1) Mail addressed to the excavator.
(2) Telephone.
(3) Electronic notification, such as email.
(4) Personal visit.
(5) Excavator awareness seminars conducted by the operator acting alone, with other underground facility operators, or through one-call notification system(s) in which the operator participates may supplement actual notification activities.

The operator should consider documenting these actions. Procedures for periodic renotification of excavators should be established based upon use of the program.

(b) The public. Operators should consider the following methods for notification of the public about the operators' damage prevention programs. These methods may also be used to complement and reinforce the message excavators receive from the actual notification methods listed under 2.4(a) above.
(1) Mailings.
(2) Bill stuffers.
(3) Handouts.
(4) Newspaper, magazine, television, or radio advertisements.
(5) Speakers supplied to local groups.
(6) Using permitting authorities and public officials to disseminate information.
(7) Joint mailings with other utilities.
(8) Vehicle advertising signboards.
(9) Decals for construction equipment and the pipeline operator's vehicles.
(10) Specialty advertising, such as bumper stickers or imprinted mementos.
(11) Notices in telephone directories.
(12) Public education programs related to §192.616.
(13) School programs.
(14) Personal visits.
(15) Maps.
(16) Exhibits or displays at appropriate public gatherings.
(17) News releases or interviews.
(18) Specific information packets designed for distribution to individual dwelling units at apartments

and condominiums.

(19) Specific information packets designed for distribution to businesses for employee education.
(20) Electronic communications, such as web pages, email, or social media.
(21) Billboards or signs.
(22) News articles (as opposed to advertising) covering safety functions, programs, messages or available information.

2.5 *Information to be communicated*.

Entities that may engage in excavation activities should be informed of the purpose of the program, how they can learn the location of underground pipelines before commencing excavation activities, and actions to be taken if the pipeline or its related components, such as tracer wire, warning tape, and passive locating devices, are hit or damaged. Illustrations or pictures of the various types of pipeline locations should be included. Program information should also advise that even minor residential activities, such as installing fences or performing landscaping, could cause pipeline damage.

(a) The programs and methods of informing entities that may perform excavation activity as described in 2.4 above should be designed to educate excavators about their obligations under applicable state laws and regulations, including the following.
  (1) How to provide notice of intent to dig, emphasizing the importance of using a one-call notification system (e.g., 811), where applicable.
  (2) How far in advance of excavation activity must the notice of intent to dig be provided.
  (3) Waiting the required time to allow operators to mark their facilities.
  (4) Verifying the location of facilities by hand digging test holes.
  (5) Support and protection of exposed facilities.
  (6) Minimum clearances of powered equipment from facilities.
  (7) Preservation of markings.
  (8) Pipe support, backfill, and compaction requirements.
  (9) Reporting discovery of unknown underground facilities.
  (10) Reporting damages or emergencies. See §192.616.
  (11) Pre-marking the excavation area with white paint.
  (12) Avoidance of disturbing cast iron facilities.
  (13) Safe excavation, support, and backfilling requirements unique to cast iron facilities.
(b) In addition, the following should be addressed in communications with excavators.
  (1) The importance of promptly reporting damage of the facilities to the pipeline operator, securing the area, and standing by at a safe distance.
  (2) Avoiding any attempt to repair the damage or restrict the flow of gas and leaving necessary repairs to be made by the pipeline operator. This includes the following considerations.
    (i) Allow the gas to vent to atmosphere.
    (ii) Do not put out the flame if gas ignites, but let it burn. Burning gas will not explode.
    (iii) Do not cover the damaged pipe with dirt as a means of stopping the leak.
    (iv) Do not kink or crimp gas pipe.
    (v) Do not attempt to plug damaged pipe.
  (3) Denting, gouging, and surface damage that appears minor can lead to future failure.
  (4) The serious consequences that can result from coating damage.
  (5) See guide material under §192.616 for information to be communicated regarding gas pipeline emergencies.
  (6) The importance of properly communicating information regarding GPS readings, when they are used.
    (i) This includes use of GPS devices that are WAAS-enabled (Wide Area Augmentation System), which is intended to increase the accuracy of GPS readings.
    (ii) Verify that the reference datum selected for the GPS coordinates is the same reference datum used by the one-call center (typically NAD 83).
    (iii) GPS coordinate nomenclature should be the same as that used by the one-call center. Typically "Decimal Degrees" format (e.g., -30.8910972) is used instead of the other two common GPS formats known as "Degrees, Minutes, and Seconds" (e.g., -30$^{o}$ 53’ 27.95")

and "Degrees and Decimal Minutes" (e.g., -30º 53.4658').

(c) Railroad operators should be made aware of concerns specific to pipeline operators, including how train derailments and response activities related to these accidents could affect the pipeline.
(d) Operators of cast iron systems should instruct builders, designers, and excavators regarding areas in their territory where cast iron facilities exist.
(e) Operators of cast iron systems may plan and design cast iron main replacements in conjunction with, or in advance of, local infrastructure replacement projects, such as paving projects and replacement of water or sewer facilities. This practice not only becomes economical because of the restoration savings, it also reduces risk of cast iron failure before, during, or after construction.
(f) Where past or present trenchless technology practices exist, operators should communicate the possibility of cross bores affecting the sewer mains and laterals. Audience should include water and sewer utilities, residents, plumbing contractors, and rental equipment stores. See OTD-12/0003, "Cross Bore Best Practices – Best Practices Guide."

2.6 *Receiving excavation notification*.

The operator should establish a telephone number and mailing address for receiving notifications of planned excavation activities in areas where its underground facilities are not covered by a one-call system. Provisions should be made for recording all notifications (e.g., using a log, form, or memo), and for the retention of such records, whether the notifications are received through a one-call system or directly from the excavator. The record should include the following.

(a) Name of person giving notification.
(b) Name of entity which will be conducting excavation activities.
(c) Telephone number for contacting the entity.
(d) Location of the planned excavation activities.
(e) Date and time of commencement of excavation activities.
(f) Type and scope of excavation activities.

Participation in a one-call system does not preclude the operator from receiving such notification directly from individuals, such as may result from observation of a pipeline marker. Operators should inform callers to make notifications directly to the one-call system.

2.7 *Responding to excavation notification*.

(a) Preparation. The operator should develop procedures for responding to notifications of intent to excavate. Consideration should be given to the following.
    (1) How information about the location of existing and newly installed facilities may be obtained from maps, records, digital or aerial imagery, or field investigation. If the operator's records include GPS coordinates, the reference datum and nomenclature to be used should be clearly documented.
    (2) How individuals responding to excavation notifications can have access to up-to-date pipeline alignment and as-built drawings.
    (3) Standards for marking facilities consistent with the field conditions, including items such as the use of paint on paved areas and stakes, and signs or flags in unpaved areas. A reference for marking facilities is the Common Ground Alliance's "Best Practices" Guide, available at https://commongroundalliance.com/best-practices-guide.
    (4) Availability of personnel who are qualified (see Subpart N) to mark facilities as necessary.
    (5) The potential for facility markings to become obscured prior to, or during, excavation activity and appropriate action to be taken.
    (6) Whether a response to the excavator should be made when the operator has no facilities located in the area of excavation activity. The operator should also review state and local regulations to determine if other response requirements apply.
(b) Response. Where facilities exist in the area of excavation activity, the operator should respond to the notification prior to the planned start of the excavation activity. The operator should consider documenting the response. The response should include the following.
    (1) Marking the operator's pipeline facilities, including laterals, in the area of the proposed

excavation activity. In areas where the pipeline facilities are curved or make sharp bends, consider the visibility and frequency of markings. Individually mark pipeline facilities located in the same trench or right-of-way. If metallic facilities are exposed during locating activities, see guide material under §192.459.

(2) Conducting an onsite meeting if there is potential for misunderstanding concerning the location of facilities or the procedure for marking.

(3) Reviewing for accuracy any maps, drawings, or records supplied to an excavator to assist in locating underground facilities. Unless field checked, it is suggested that they be marked with a note such as "Not responsible for accuracy, verify by hand digging."

(4) Participating in, coordinating, or conducting pre-excavation meetings, when appropriate, with other facility owners and excavators. Special attention should be given to large or complex projects. Discuss aspects of the planned excavation activities, marking schedules, and lines of communication. Provide the excavators with information about the underground pipeline facilities in order to avoid damage. The operator should discuss the potential for facility markings becoming obscured and corrective measures.

(5) Ensuring adequate separation between a buried foreign structure to be installed and the adjacent pipeline by coordination with the owner or operator of the foreign structure. See guide material under §192.325.

(6) Advising excavators who plan to use trenchless methods (e.g., boring) of potential damage to gas pipeline facilities. See Guide Material Appendix G-192-6 for protecting existing gas facilities.

(7) For operators of cast iron facilities, advising excavators at the job site of the following.
   (i) Cast iron may fail when subjected to undermining and disturbance.
   (ii) How to avoid undermining or disturbing the cast iron facilities.
   (iii) Notify the operator immediately if the main is either undermined or disturbed.

(8) For operators of cast iron facilities, documenting known conditions where facilities have been undermined or disturbed to aid in the study for determining future replacement needs as required under §192.755. Also, see Guide Material Appendix G-192-18, Section 4.

(c) Records. Operators should document their responses to excavation notifications.

2.8 *Inspecting pipelines*.

(a) Need and schedule. Each notification should be evaluated to determine the need for, and the extent of, the inspection. Where required, the inspection may include periodic or full-time surveillance and may include leak surveys during and after construction. The operator should consider maintaining field contact with the excavator during the excavation activities to avoid potential problems and to promptly resolve any problems that may arise. The following factors should be considered in determining the need for, and extent of, inspections.
   (1) Type and duration of the excavation activity involved.
   (2) Proximity to the operator's facilities.
   (3) Located within a High Consequence Area (HCA). If the inspection work is on a covered segment of transmission line, the operator is required to follow the additional items described in §192.935. For threat of third-party damage, see 2 of the guide material under §192.935.
   (4) Type of excavating equipment involved.
   (5) Importance of the operator's facilities.
   (6) Type of area in which the excavation activity is being performed.
   (7) Potential for a serious incident should damage occur.
   (8) Past experience of the excavator.
   (9) Potential for damage occurring which may not be easily recognized by the excavator, such as improper support during excavation and backfill or trenchless installations (e.g., boring).
   (10) Potential for facility markings to become obscured.

(b) Onsite inspection. When onsite inspection is performed, the operator should use qualified personnel as necessary to ensure that the excavator is doing the following (see OPS Advisory Bulletin ADB-06-01; 71 FR 2613, Jan. 17, 2006; reference Guide Material Appendix G-192-1, Section 2).
   (1) Verifying the location of the facilities by hand digging test holes.
   (2) Supporting and protecting exposed facilities.

(3) Maintaining minimum clearances of powered equipment from facilities.
(4) Preserving location markings.
(5) Practicing safe excavation and backfill procedures related to the protection of operator facilities. When a high risk condition is identified, the operator should consider locating the nearest valves or shut-off points necessary to isolate the site. The operator should check the operability of those valves and maintain as necessary (see guide material under §192.747).

(c) Settlement. The operator should pay particular attention, during and after excavation activities, to the possibility of joint leaks and breaks due to settlement when excavation activities occur, especially in cast iron, threaded-coupled steel, and mechanical-compression joints.
(d) Cast iron pipelines. See Guide Material Appendix G-192-18.
(e) Plastic and steel pipelines. The operator should inspect plastic pipelines for gouges and steel pipelines for coating damage and gouges, when necessary, before the exposed pipeline is backfilled. If metallic facilities are exposed during locating activities, see guide material under §192.459.
(f) Blasting. Leak surveys should be conducted on pipelines that could have been affected by blasting. For additional guidelines related to blasting activities, see Guide Material Appendix G-192-16.
(g) Trenchless installations. Leak surveys should be considered on pipelines that could be affected by trenchless installations. See Guide Material Appendix G-192-6 for damage prevention considerations while performing directional drilling or using other trenchless technologies.
(h) Damage concerns. When the operator is aware that its pipeline has been hit or almost hit, the excavator's practices and procedures that are likely to affect the operator's pipeline should be evaluated before excavation activity continues.
(i) Transmission lines. A reference for inspecting transmission lines is API RP 1166, "Excavation Monitoring and Observation."

*2.9 Protection at active construction sites.*
For temporary markings, see 4 of the guide material under §192.319.

## §192.615
## Emergency plans.

*[Effective Date: 02/01/10]*

**(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 the appropriate public safety answering point (i.e., 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. An operator must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone number(s) for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies.**

**(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) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released gas to life, property, or the environment.**

**(7) Making safe any actual or potential hazard to life or property.**

**(8) Notifying the appropriate public safety answering point (i.e., 9-1-1 emergency call center) where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving a notification of potential rupture, as defined in §192.3, to coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of §§192.179, 192.634, or 192.636.**

**(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 the operator's emergency plans and requirements set forth in §192.631, 192.634, and 192.636.**

**(12) Each operator must develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in §192.3, is an actual rupture event or a non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture and identify an actual rupture. For operators installing valves in accordance with §192.179(e), § 192.179(f), or that are subject to the requirements in §192.634, those procedures must provide for rupture identification as soon as practicable.**

**(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 the appropriate public safety answering point (*i.e.,* 9-1-1 emergency call center) where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, as well as 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 13586, Mar. 31, 1976; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-112, 74 FR 63310, Dec. 3, 2009; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

## GUIDE MATERIAL

*Notes:*
(1) Although not required, operators should consider developing an emergency plan for Type B gathering lines.
(2) To differentiate between operators' emergency response personnel and processes and those of public agencies and administrations, the term *operator* (or a variant) is used to denote pipeline operators' personnel and processes. Similarly, the term *local* is used for public agencies, such as fire, police, and other public officials.
(3) Some activities performed as requirements for emergency plans may also be used to satisfy similar program requirements under §§192.614, 192.616, 192.620(d)(2), and 192.935.

## 1 WRITTEN EMERGENCY PROCEDURES (§192.615(a))

(a) Written procedures should state the purpose and objectives of the operator's emergency plan and provide the basis for instructions to their appropriate personnel. The objective of the plan should be to ensure that operator personnel who could be involved in an emergency are prepared to recognize and deal with the situation in an expeditious and safe manner.
(b) Establishing written procedures may require that parts of the plan be developed and maintained in coordination with local emergency response personnel and with other entities in or near the pipeline rights-of-way (e.g., other utilities, highway authorities, and railroads) that may need to respond to a pipeline emergency.
(c) Written procedures should also include instructions on interfacing with the Incident Command System (ICS) typically used by local emergency responders. See 1.2 below for interfacing with an ICS and 1.10 below for general information about the ICS.
(d) If applicable, written procedures should include a reference to Control Room Management procedures associated with a controller's roles and responsibilities during emergency conditions. See 3.2(c) of the guide material under §192.631
(e) To ensure the safety of the general public, an operator's written procedures should provide for the following as applicable.

*1.1 Receiving, identifying, and classifying emergencies*.
(a) Provisions should be made to ensure prompt and adequate handling of all calls, reports, or indications concerning emergencies (see §192.615(a)(3)), whether they are from customers, the public, operator employees, SCADA systems, or other sources. The following should be included.
  (1) Arrangements for receiving notification of an emergency at any hour of the day. When an answering service is used, answering service personnel should be trained and have updated emergency call-out lists of operator personnel for emergency response.
  (2) Directions to operator employees who receive calls considering the following.
    (i) The information received should be assessed in order for the operator to react properly to the call and to inform the caller of precautionary actions to be taken prior to the arrival of operator personnel. Personnel receiving notices of gas leaks or odors should obtain the following basic information from the caller and inform the caller that access will be required.
      (A) Name.
      (B) Address of leak or odor.
      (C) Telephone number.
      (D) Reason for call.
      (E) Location of the odor (inside or outside).
    (ii) Additional questions that could be asked to assist in determining the priority for action, and if additional instructions should be provided to the caller, include the following.
      (A) Strength of odor?
      (B) Length of time odor has been present?
      (C) Was anyone working on indoor gas piping or appliances?
      (D) Is there any construction in the area?
      (E) Can you hear evidence of escaping gas?

(F) What type of building or facility is involved?

(iii) If the answers to these or other questions indicate a potentially hazardous situation, consideration should be given to providing additional instructions to the caller, such as the following.

(A) Do not create a source of ignition by operating switches, electrical appliances, or portable telephones.

(B) Evacuate the area and wait for operator personnel to arrive.

(C) Call back from a safe location to provide additional information for response personnel.

*Note:* The operator should confirm that the caller understands the instructions and repeat instructions as necessary.

(iv) If gas leakage or other hazard is determined to be significant, the operator should consider contacting the local emergency response agency. The operator should call 911 where appropriate, informing them of the emergency situation and providing pertinent information.

(3) Operator personnel receiving emergency calls should receive periodic refresher training on leak call procedures, communication skills, and reporting procedures. Periodic performance reviews should be conducted during actual leak calls.

(b) Instructions to operator personnel should ensure that the information received is evaluated to determine the priority for action. Some situations call for operator personnel to be dispatched promptly for an on-the-scene investigation. Those personnel should respond in an urgent manner giving a potential emergency top priority until the severity of the situation has been determined. Some situations require that priority be given to other actions, such as notification to gas control, other operator or local emergency response personnel. See 3.3 below.

Examples of emergency situations that require immediate response include the following.

(1) Gas ignition or explosion.
(2) A hissing noise is present or there is any indication of a broken or open-ended pipe.
(3) Report of a pulled service or damaged facility.
(4) Gas odor throughout the premise or building.
(5) Other identified (i.e., operator designated) emergencies.

(c) In a combination utility (e.g., gas with electric, water or other utilities), training should be provided to personnel of other utilities or divisions to inform the gas operator and other applicable entities of gas leak, gas odor, or other pertinent information provided by customers or the general public.

*1.2 Establishing and maintaining adequate means of communication*.

(a) Arrangements made for establishing and maintaining adequate public and operator communications should be described. These arrangements should include means of communication with appropriate fire, police, and other public officials, and should consider the need for the following.

(1) Continuously updated operator and public emergency call lists that will show how to contact personnel that may be required to respond to an emergency at any hour.
(2) Multiple telephone trunk lines to the emergency operations center.
(3) Additional switchboard facilities and personnel.
(4) "Unlisted" telephone service to ensure accessibility to operator-only calls.
(5) Additional fixed and mobile radio equipment.
(6) Standby electrical generating equipment for communications power supply.
(7) Dissemination of accurate information to the news media and cooperation with the news media on the scene.
(8) A social media program to gather and disseminate information.

(b) Instructions for working effectively with the local ICS should be described as follows.

(1) When local emergency responders have set up an Incident Command prior to the arrival of operator personnel:

(i) The first operator person to arrive should introduce himself to the Incident Commander as the representative from the gas pipeline operator, and

(ii) That person remains the point of contact until the incident has been made safe or until relieved of that duty by another operator representative.

(2) When local emergency responders are not yet on the scene:
(i) The first person representing the operator to arrive will serve as Command, and
(ii) That person should assess the situation and take, or direct, all necessary actions to protect people, protect property, and secure the flow of gas.

(3) If local emergency responders arrive later and set up an ICS:
(i) The Command for the gas pipeline operator should introduce himself as the point of contact for the operator, brief the local Incident Commander, and
(ii) That person should remain the point of contact until the incident has been made safe or until relieved of that duty by another operator representative.

(c) Consider providing operator's first-responder personnel with intrinsically safe communication devices to carry with them while on duty. Be aware of communication blind spots.

*1.3 Prompt and effective response to each type of emergency.*

Various types of emergencies will require different responses in order to evaluate and mitigate the hazard. Consideration should be given to the following.

(a) Emergencies involving gas detected in or near buildings should be prioritized in order to have sufficient operator personnel for response. For leak classification and action criteria, refer to Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems. See §192.605(b)(11), which requires procedures for prompt response to reports of a gas odor in or near buildings.

(b) Emergencies involving damage to buried facilities during excavation activities should be assessed for potential hidden and multiple leak locations.

(c) Emergencies involving fire located on or near pipeline facilities may require those facilities to be isolated. If a major delivery point is involved, an alternative gas supply may be needed.

(d) Emergencies involving an explosion on or near pipeline facilities may result in damage from fire and shock waves.

(e) Emergencies involving blowing or ignited gas may hinder local emergency responders' search and rescue efforts.

(f) Natural disasters, such as earthquakes and other significant earth movement (e.g., landslides, mudslides, sinkholes), floods, hurricanes, tidal waves, tornadoes, or wildfires, might affect the safe operation of pipeline facilities in many different ways. Manmade disasters, such as mine subsidence, sabotage, infrastructure collapse, or corrosive chemical discharge, might also affect safe operations. Operators affected by these disasters should dispatch personnel to the areas as soon as practicable to evaluate the situation and proceed with emergency response related to their gas facilities, as necessary, to keep or make conditions safe. Operators of pipeline facilities affected by natural disasters should address these situations in the emergency procedures and consider preparing a disaster plan including site-specific procedures, if appropriate. The procedures and plan may include the items listed below.

<u>Note:</u> Multiple advisory bulletins have been issued regarding the potential for damage to pipeline facilities caused by the passage of hurricanes and flooding. For examples, see OPS Advisory Bulletin ADB-2015-02 (80 FR 36042, June 23, 2015; see Guide Material Appendix G-192-1, Section 2) and the advisory bulletin referenced in 6 of the guide material under §192.613.

(1) Information on responsibilities for operator personnel communication and work assignments.
(2) Information on alternative reporting locations for operator personnel in case the primary location is damaged or inaccessible.
(3) Procedures to assess damage and mitigate hazardous conditions, which may include the following.
(i) Establishing an operations and communications command center.
(ii) Establishing a field command post.
(iii) Determining personnel, material, and equipment requirements.
(iv) Deploying personnel to sites and locations where they can take appropriate actions, such as shutdown, isolation, or containment.

(v) Evaluating the accessibility of pipeline facilities that may be in jeopardy such as valves and regulator stations needed to isolate the system.
(vi) Performing frequent patrols to evaluate the effects on pipeline facilities.
(vii) Determining the extent of damage to pipeline facilities.
(viii) Ensuring line markers are still in place or replaced in a timely manner for operator-defined critical locations or facilities.
(ix) Determining if facilities that are normally above ground (e.g., valves, regulators, relief devices) have become submerged and are in danger of being struck by vessels or debris. Facilities in danger of being struck by vessels should be marked with an appropriate buoy if the locations can be reached safely.
(x) Performing surveys to determine the depth of cover over pipelines and the condition of any exposed pipelines, such as those crossing scour holes or where water channels have changed. For pipelines in the Gulf of Mexico and its inlets with waters less than 15 feet deep, see §192.612.
(xi) Evaluating right-of-way conditions at water crossings during the flooding and after waters subside by performing patrols, including appropriate overflights. Notify appropriate staff of any localized or systemic flooding to determine whether pipeline crossings may have been damaged or would be in imminent jeopardy from future flooding.

*Note:* After the emergency response, information about the presence of pipelines and the risks posed by reduced cover should be shared with the affected landowners and with contractors, highway departments, and others involved in restoration activities following the natural or manmade disaster. Agricultural agencies may help inform farmers of the potential hazard from reduced cover.

(4) Procedures to re-establish normal operations including service restoration and progress tracking and reporting. For large-scale outages of distribution systems, see Guide Material Appendix G-192-7.
(5) Other considerations.
(i) Maintaining mutual assistance agreements with other pipeline operators.
(ii) Providing accommodations for operator personnel and other assisting personnel.
(iii) Shutting off gas service to an affected area if evacuations of that area are being made by police or fire departments.

1.4 *Assuring the availability of personnel, equipment, tools, and materials*.

Arrangements made to assure the availability of personnel, equipment, tools, and materials that may be needed should be described in accordance with the type of emergency. These arrangements should include the assignment of responsibilities for coordinating, directing and performing emergency functions, including the following.

(a) Responsibility for overall coordination, which may be at the operator's area facilities or at the operating executive level, depending on the scope of the emergency.
(b) Responsibility for executing the operator's emergency operations, based on the scope of the emergency.
(c) Determination of departmental functions or services during an emergency, including determination of individual job assignments required to implement the plan.
(d) Determination of coordination required between departments, including provision for bypassing the normal chain of command as necessitated by the emergency.
(e) Determination of coordination required to implement mutual aid agreements.
(f) Responsibility for providing accurate information and cooperation with the news media.
(g) Establishment of an operator's first-responder checklist of tools and equipment, such as combustible gas indicators (capable of detecting LEL), probe rods, radios, cones, grates, barricades, and manhole cover lifting devices. The list should be reviewed and updated as needed, and the operator should periodically verify that their first responders are properly equipped.

1.5 *Controlling emergency situations*.

Actions that may be initiated by the first employee arriving at the scene in order to protect people and property should be described. These actions may include the following.

(a) Determining the scope of the emergency.
(b) Evacuating and preventing access to premises that are or may be affected.
(c) Preventing accidental ignition.
(d) Reporting to the appropriate supervisor on the situation and requesting further instructions or assistance, if needed.

*1.6 Emergency shutdown and pressure reduction*.

(a) Provisions for shutdown or pressure reduction in the pipeline system as may be necessary to minimize hazards should be described. The plans should include the following.
  (1) Circumstances under which available shutdown, pressure reduction, or system isolation methods are applicable. Considerations should include the following.
    (i) Access to, and operability of, valves located in areas prone to high water or flooding conditions.
    (ii) Proximity to buildings and other structures.
    (iii) Proximity to local emergency responders' search and rescue area.
  (2) Circumstances under which natural gas might be allowed to safely escape to the atmosphere (i.e., vent) until shutdown or repair.
    (i) Some possible reasons for using this alternative are as follows.
      (A) Curtailment will affect critical customers (e.g., hospitals).
      (B) Curtailment will affect large numbers of customers during adverse weather conditions.
      (C) Line break or leak is remotely located and does not cause a hazard to the public or property.
    (ii) Some factors to consider are as follows.
      (A) Sources of ignition.
      (B) Leak or damage location (rural vs. urban).
      (C) Proximity to buildings and other structures.
      (D) Local emergency responders' ability to access the search and rescue area.
      (E) Ability to make and keep the area safe while gas vents.
      (F) Ability to coordinate with operator and local emergency responders and public officials.
  (3) Lists or maps of valve locations, regulator locations, compressor schematics, and blowdown locations.
  (4) Maps or other records to identify sections of the system that will be affected by the operation of each valve or other permanent shutdown device.
  (5) Provision for positive identification of critical valves and other permanent facilities required for shutdown. See 2.2 of the guide material under §192.605.
  (6) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
  (7) Provisions for notifying affected customers.
  (8) Provisions for confirming that the shutdown or pressure reduction was effective.
(b) Distribution system plans should include consideration of the potential hazards associated with an outage and the need to minimize the extent of an outage, and to expedite service restoration. In addition to the use of any existing emergency valves within a distribution system, consideration should also be given to other methods of stopping gas flow, such as:
  (1) Injecting viscous materials or polyurethane foam through drip risers or any other available connections to the main.
  (2) Use of squeeze-off or bagging-off techniques.

*1.7 Making safe any actual or potential hazard*.

Provisions should be described for identifying, locating, and making safe any actual or potential hazard. These may include the following.

(a) Controlling pedestrian and vehicular traffic in the area.
(b) Eliminating potential sources of ignition.
(c) Controlling the flow of leaking gas and its migration. See Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems.

(d) Ventilating affected premises.
(e) Venting the area of the leak by removing manhole covers, barholing, installing vent holes, or other means.
(f) Determining the full extent of the hazardous area, including the discovery of gas migration and secondary damage such as the following.
   (1) Deformation of a gas service line indicating that the service line might be separated underground near a foundation wall or at an inside meter set assembly.
   (2) Multiple underground leaks that may have occurred, allowing gas to migrate into adjacent buildings.
   (3) Potential pipe separation and gas release at unseen underground locations that may result in gas entering adjacent buildings, or following or entering other underground structures connected to buildings.
(g) Monitoring for a change in the extent of the hazardous area.
(h) Determining whether there are utilities whose proximity to the pipeline may affect the response.
   (1) Visually identify the presence of electric and other utilities surrounding the pipeline facility.
   (2) Evaluate the potential risk associated with the continued operation of the surrounding utilities.
   (3) Use the local ICS to contact the owner of the surrounding utilities, as necessary, to implement a more effective and coordinated emergency response.
(i) Coordinating the actions to be taken with fire, police, and other public officials, including the following.
   (1) Search and rescue efforts.
   (2) Ensuring information pertinent to emergency response is shared in a timely manner.

*1.8 Restoration of service*.

Planning for the safe restoration of service to all facilities affected by the emergency, after proper corrective measures have been taken, should include consideration of the following.

(a) Provisions for safe restoration of service should include the following.
   (1) Turn-off and turn-on of service to customers, including strict control of turn-off and turn-on orders to assure safety in operation.
   (2) Purging and repressurizing of pipeline facilities. For service lines containing an EFV, see guide material under §192.381 for purging considerations.
   (3) Resurvey of the area involved in a leak incident to locate any additional leaks.
(b) Execution of the repair and restoration of service functions will necessitate prior planning, such as the following.
   (1) Sectionalizing to reduce extent of outages and to expedite turn-on following a major outage.
   (2) Lists and maps for valve locations, regulator locations, and blowoff or purge locations.
   (3) Provisions for positive identification of valves and regulator facilities. See 2.2 of the guide material under §192.605.
   (4) Equipment checklist for repair crews.
   (5) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
   (6) Emergency supply connections with other gas companies and procedures for making use of such connections.
   (7) List of contractors, utilities, and municipalities that have agreed to provide equipment and workers to assist with repair and service restoration. Procedures for securing and utilizing this equipment and workforce should be described.
   (8) Prearranged use of facilities, owned by others, for temporary operating headquarters for repair and restoration activities. Arrangements should also be made for all necessary support functions for such temporary operating headquarters.
   (9) Cooperation with appropriate civil organizations in providing housing and feeding facilities for persons requiring shelter during an outage in severe weather.
   (10) Arrangements to maintain service to critical customers, such as hospitals, to the degree possible during a general service curtailment or outage. In addition, a similar priority should be assigned for turn-off activities.
(c) For large-scale outages, also see Guide Material Appendix G-192-7.

*1.9 Providing for investigation of failures*.

Instructions for initiating investigation of failures in accordance with §192.617 should include the following, where applicable.

(a) Keeping a log of significant events and of actions taken.
(b) Preserving failed facilities or equipment for analysis, as may be appropriate.
(c) Obtaining and submitting information required by jurisdictional regulatory agencies.
(d) Including the requirement for post-accident / incident drug and alcohol testing. See Part 199 – Drug and Alcohol Testing and OPS Advisory Bulletin ADB-2012-02 (77 FR 10666, Feb. 23, 2012; see Guide Material Appendix G-192-1, Section 2).

*1.10 Incident Command System (ICS).*

(a) In the context of applying the ICS, the Federal Emergency Management Agency (FEMA) has defined the term incident as "an occurrence, either caused by humans or natural phenomena, that requires response actions to prevent or minimize loss of life or damage to property and/or the environment." Certain gas emergencies could fall within the FEMA definition of an incident. Examples of FEMA incidents include the following.
    (1) Fire, both structural and wildland.
    (2) Natural disasters, such as tornadoes, floods, ice storms, or earthquakes.
    (3) Human and animal disease outbreaks.
    (4) Search and rescue missions.
    (5) Hazardous materials incidents.
    (6) Criminal acts and crime scene investigations.
    (7) Terrorist incidents, including the use of weapons of mass destruction.
    (8) National Special Security Events, which are designated by the U.S. Department of Homeland Security (e.g., Presidential inaugurations, national political conventions, major sporting events).
    (9) Other planned events, such as parades or demonstrations.
(b) The ICS is a management system for dealing with emergencies. It has been developed from reviewing past emergencies and formalized into a structured system by FEMA and other emergency response agencies. It is a consistently applied system for controlling on-site personnel, facilities, equipment, and communications in an emergency. It is a designated system used from the time a FEMA incident occurs until the requirements for implementing the ICS no longer exist.
(c) When an operator and local emergency responders implement an ICS, respective plans may differ but should be based on similar principles so the plans are compatible. The ICS may be used for small or large incidents, remaining adequately flexible to adjust to the changing needs of an incident.
(d) The ICS functions typically include the following.
    (1) Safety – public and employees.
    (2) Security – utilize operator or local public safety personnel.
    (3) Commander responsibilities – establish command center, transfer of command.
    (4) Operational – incident stabilization plan, repair plan.
    (5) Logistics – material, equipment, other resources.
    (6) Public relations – communications, notifications, information liaison.
    (7) Personnel management.

(e) The ICS supports responders and decision makers by providing the data they need through effective information and intelligence management. The data provided may include information on the following.
    (1) Maps and records for critical infrastructure and other facilities.
    (2) Load studies.
    (3) Affected customers, including residential, commercial, and industrial customers.
(f) Additional information on the ICS can be found at: training.fema.gov/emiweb/is/icsresource/

*1.11 Role of control room during an emergency.*

If applicable, an operator should provide controllers with procedures and tools when controllers are required to respond to an emergency in accordance with §192.631.

## 2 ACQUAINT APPROPRIATE OPERATING AND MAINTENANCE EMPLOYEES WITH THE PROCEDURES (§192.615(b))

Each operator should have a program to assure that all operating and maintenance personnel who may be required to respond to an emergency are acquainted with the requirements of the written emergency procedures. The program should include the following.

*2.1 Provide employees access to emergency procedures manual*.
The latest edition of the written emergency procedures and plans should be easily accessible so that employees may become familiar with them. Consideration should be given to placing a copy near telephones and base radio units that might be used to notify the operating personnel of an emergency.

*2.2 Training of employees*.
Appropriate operating and maintenance employees should be trained to ensure that they are knowledgeable of the requirements of the written emergency procedures. Persons providing training of the emergency procedures should be knowledgeable in emergency response and training techniques. Consideration should be given to conducting classroom or field simulated emergency exercises involving appropriate personnel, such as operating, maintenance, and dispatch personnel, including those monitoring and controlling operations of remote facilities. Emergency exercises should include worst-case scenarios. The effectiveness of the training may be verified by methods such as oral test, written test, or evaluating performance during simulated emergencies. Such verification of the effectiveness of training should be documented.

Those responsible for instruction of operator employees should place special emphasis on the following.
(a) Understanding the properties and behavior of the gas, as related to types of potential hazards, including the recognition of, and the appropriate actions to take regarding, hazardous leaks.
(b) Coordinated execution of the operator's written emergency procedures, including coordination among different functional groups (e.g., between gas control and operator emergency response personnel in an emergency situation).
(c) Knowledge of how emergency control is exercised in various sections of the system, including identification and operation of key valves.
(d) Ability to use operator's maps or other facility records.
(e) Responsibilities of each employee responding to an emergency and the relationship to the emergency procedure. This should include responsibilities related to interacting effectively with local emergency responders in an Incident Command System.
(f) Evaluation of reports of gas odor and other potential emergencies.
(g) Response to different types of emergency situations, such as gas escaping inside or outside and gas burning inside or outside. Appropriate actions should include avoiding the use of doorbells or buzzers when responding to possible leaks, evacuation, elimination of ignition sources, gas shutoff, ventilation, and other precautionary measures.
(h) Familiarization with tools and equipment appropriate to the particular function or situation.
(i) Fulfillment of the recordkeeping requirements called for under the written emergency procedures. This should include a log of the emergency and the validation and documentation of the corrective action taken.

*2.3 Review of employee activities*.
Following each emergency, employee activities should be reviewed, by examining the log of events and actions taken, to determine whether the procedures were effectively followed. Consideration should be given especially to whether responses to the emergency were timely. In addition, consideration should be given to the need for changes in the written procedures as may be indicated by the experience gained during the emergency.

## 3 LIAISON WITH PUBLIC OFFICIALS (§192.615(c)) AND OPERATORS OF FACILITIES IN THE VICINITY OF THE PIPELINE

*Note:* Section 192.616 requires most operators to develop and implement a written continuing public education program that follows the guidance provided in API RP 1162 for stakeholder audiences that include emergency officials and public officials. Information provided to emergency and public officials under a public awareness program may address some of the requirements of §192.615(c), but may not adequately address all the "liaison" requirements. The liaison requirement of §192.615(c) is expected to bring an operator and respective emergency responders and public officials together to exchange information regarding emergency response that is specific to the operator's systems and facilities. Added guidance for liaison with emergency officials is provided below.

Those responsible for establishing liaison with appropriate public officials and operators of facilities in the vicinity of the pipeline (e.g., telephone, electric, gas, cable, water, sewer, and railroads), with respect to emergency procedures, should consider the following.

*3.1 Compiling current information on the resources of government organizations.*

- (a) Organization's name.
- (b) Type of responsibility.
- (c) Geographic area covered.
- (d) Availability to assist in case of a pipeline emergency.
- (e) Responsibility and resources for fire, bodily injury, control, and area evacuation problems in connection with a gas pipeline emergency.
- (f) Type, size, and capacity of equipment and vehicles.
- (g) Procedures to facilitate prompt communications in emergencies.
- (h) Level of training of responders.

*3.2 Acquainting public officials with emergency procedures*.

- (a) Appropriate fire, police, and other public officials should be informed of the availability, capability, and location of the operator's personnel, equipment, and materials for response to gas pipeline emergencies. They should be provided with a list of the appropriate employees who can be contacted at any hour. The importance of immediate contact should be stressed.
- (b) Consideration should be given to involving local public emergency response personnel in operator-simulated emergency exercises and post-exercise critiques. In areas where multiple pipeline operators have facilities, consideration should be given to joint emergency training and liaison activities with the local emergency response officials.
- (c) For additional information on this subject, see OPS Advisory Bulletin ADB-10-08 (75 FR 67807, Nov. 3, 2010; see Guide Material Appendix G-192-1, Section 2).

*3.3 Identifying emergencies that require notification to and from public officials*.

- (a) The types of emergencies that might require notification of public officials by gas system operators include the following.
  - (1) A serious fire or a fire on adjacent property.
  - (2) Serious bodily injury.
  - (3) Where the number of people involved or the spectators are too numerous for the operator to handle.
  - (4) Adjacent to public rights-of-way where the public could be endangered.
  - (5) Where an area patrol or area evacuation is needed.
  - (6) An incident in a highly populated area.
- (b) The types of emergencies that might require notification to operators by public officials include the following.
  - (1) Report of gas odor.
  - (2) Damage to gas facilities.
  - (3) Operation of a gas system valve by non-operator personnel.

(4) Report of a gas outage.

3.4 *Plan with public officials and operators of facilities in the vicinity of the pipeline for mutual assistance*.

(a) Operator personnel should establish and maintain liaison with appropriate fire, police, and other public officials and operators of facilities in the vicinity of the pipeline to plan how to engage in mutual assistance to minimize hazards to life and property. This planning should include how to work together effectively in an Incident Command System and the means to ensure communication of pertinent information id ongoing and timely during an emergency response. Consideration should be given to various situations including the following.

(1) Operator has reason to believe a hazard may exist and where local emergency personnel may be able to respond more quickly than operator personnel. Fire and police department personnel should take action toward protecting the public by means of evacuation and building ventilation, where needed, pending the arrival of operator personnel.

(2) Evacuation of buildings and properties.

(i) Advise police and fire departments that operator personnel may need to conduct leak investigations inside buildings and on properties within the area of the emergency.

(ii) The operator, police department, and fire department should plan for access to evacuated buildings and properties. The plan should include provisions to instruct personnel in charge of evacuated buildings and properties to provide a means of access, when required.

(3) Operation of electric, other utilities, or mechanical equipment located in the vicinity of the pipeline may provide sources of ignition for the gas released, may increase burning time or intensity of fires that have already started, or may delay responders who are attempting to make the situation safe.

(4) Pipeline is located in proximity to a derailed train, near or within a railroad right-of-way, where pipeline damage may not be apparent or suspected. Pipeline operators should inform railroad operators and local emergency response officials of the presence, location, and depth (if known) of their pipeline. Knowledge of pipeline existence could reduce hazards to people working at and around the accident location, and could prevent damage or rupture of the pipeline due to the movement of heavy equipment within or near the railroad right-of-way. For additional information, see OPS Advisory Bulletin ADB-2012-08 (77 FR 45417, July 31, 2012; reference Guide Material Appendix G-192-1, Section 2).

(5) Flooding has occurred or the threat of flooding might have jeopardized pipeline crossings. The following actions should be considered:

(i) Provide relevant information, such as maps, to emergency responders so appropriate response strategies can be developed.

(ii) Communicate with local and state officials to address potential concerns related to the flooding (e.g., pipeline exposures, localized flooding, ice dams, debris dams, bank erosion) that might affect pipeline integrity.

(iii) Coordinate with other pipeline operators in flood areas and establish or work with emergency response centers to act as a liaison for pipeline problems and solutions.

(6) Gas migration to other areas via underground paths (e.g., sewers or other conduits.

(b) The gas characteristics and properties, such as pressure, specific gravity, gas odor, and flammability limits, should be provided to local emergency response officials. The implications of these characteristics and properties on emergency response decisions should be thoroughly discussed. In discussions with local emergency response officials, the operator should emphasize the following.

(1) The importance of this information to local emergency response personnel arriving before operator personnel.

(2) The use of this information in making decisions, such as areas to be evacuated, traffic rerouting, and control of ignition sources.

(3) The importance of gas detectors in properly responding to an incident.

# §192.616

## Public awareness.

*[Effective Date: 01/14/08]*

**(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.**

**[Issued by Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-99, 70 FR 28833, May 19, 2005 with Amdt. 192-99 Correction, 70 FR 35041, June 16, 2005; Amdt. 192-103, 71 FR 33402, June 9, 2006; RIN 2137-AE17, 72 FR 70808, Dec. 13, 2007]**

## GUIDE MATERIAL

## 1 GENERAL

The public education program should be tailored to the type of pipeline operation (transmission, distribution, gathering) and the environment traversed by the pipeline. Section 192.616(b) requires the operator to assess the unique attributes and characteristics of the operator's facilities. Operators in the same area should attempt to coordinate their program activities to properly direct reports of emergencies and to avoid inconsistencies.

Some activities performed as requirements for public awareness may also be used to satisfy similar program requirements under §§192.614, 192.615, 192.620(d)(2), and 192.935.

Operators of petroleum gas distribution systems or smaller natural gas systems (e.g., master meter operators) subject to §192.616 should review the "Guidance Manual for Operators of LP Gas Systems" or the "Guidance Manual for Operators of Small Natural Gas Systems" available at https://www.phmsa.dot.gov/training/pipeline/guidance-manuals in addition to other references noted below.

## 2 API RP 1162

*2.1 Recommended Practice (RP).*

Guidance provided in API RP 1162 (see §192.7 for IBR) is represented as "recommended practices"; however, §192.616(b) and (c) require the operator to follow the general program recommendations of API RP 1162 unless the operator justifies in its written program or procedural manual why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

*2.2 Stakeholder audiences.*

Guidance is provided in API RP 1162, Section 3 for identifying the four stakeholder audiences, which are the affected public, emergency officials, local public officials with land use authority, and excavators. Some additional considerations for this identification process include the following.

(a) Residents located adjacent to a transmission or regulated gathering line ROW.
The extent of program coverage may vary depending on the location of the transmission or regulated gathering pipeline with respect to occupants of residences and businesses. In determining the scope of the operator's communication, the likelihood that the occupant would be able to recognize a pipeline emergency on the rights-of-way should be considered. Distance, terrain, other homes, or buildings between the occupant and the pipeline are factors that influence the ability to recognize a pipeline emergency. See 2.3(b) of the guide material under §192.614.

(b) Emergency officials and local public officials with land use authority.
See 2.3(c) of the guide material under §192.614.

(c) Excavators.
See 2.3(a) of the guide material under §192.614.

(d) Other audiences not specifically mentioned in API RP 1162.
   (1) Railroads. See 2.3(d) of the guide material under §192.614.
   (2) Operators of facilities in the vicinity of the pipeline (e.g., telephone, electric, gas, cable, water, sewer, and railroads). See 3 of the guide material under §192.615.

*2.3 Message content.*

API RP 1162 identifies several "Baseline Messages" and "Supplemental Messages" to be communicated to the stakeholder audiences. Operators are required by §192.616(b) and (c) to follow these general program recommendations, except as exempted by §192.616(c). It is often more effective to emphasize one or two messages at any given time rather than overwhelm the stakeholder audience with a "laundry list" that might be easily forgotten. If the operator chooses to convey the required messages in multiple communications to stakeholder audiences, the operator should consider including a plan, schedule, or timetable in its program for addressing each of the recommended messages.

Guidance is provided in API RP 1162, Section 4 for message content and components. Additional considerations for some of the message components include the following.

(a) Pipeline purpose — Facts about the gas distributed or transported.
(b) Leaks and pipeline emergencies – Transmission and regulated gathering lines.
    (1) Possible indicators might include the following.
        (i) A roaring, blowing, or hissing sound.
        (ii) Dirt being blown or appearing to be thrown into the air.
        (iii) Water bubbling or being blown in the air from water bodies or wet areas.
        (iv) Fire coming from the ground, appearing to burn right above the surface, or uncontrolled burning of gas.
        (v) Dead or dying vegetation on or near a ROW in an otherwise green area.
        (vi) Unusually dry or frozen spots on rights-of-way.
        (vii) An odor of gas.
    (2) Response to a pipeline leak or emergency.
        (i) Leave the area quickly and warn others to stay away.
        (ii) Report a leak or an emergency to the pipeline operator and local 911 or local emergency response agency from a safe place.
        (iii) Report pipeline damage that results in a release of gas to the local 911 or, where there is no local 911, to the local emergency response agency. In addition, consider providing information to excavators advising them of their responsibilities for reporting damage according to the PIPES Act of 2006 (49 USC 60114(d)).
        (iv) Actions to take until the operator can respond. These might include the following.
            (A) Do not attempt to operate pipeline valves.
            (B) Do not use open flames or bring anything into the area that may cause ignition (e.g., cell phones, flashlights, motor vehicles, electric or cordless tools).
            (C) Continue to warn others to stay away from the area.
(c) Leaks and pipeline emergencies — Distribution systems.
    (1) Possible indicators might include the following.
        (i) An odor of gas in a building.
        (ii) An odor of gas outside.
        (iii) An odor of gas where excavation work is in progress or has recently been completed.
        (iv) A hissing, roaring, or blowing sound.
        (v) Blowing or uncontrolled burning of gas.
        (vi) Water bubbling or being blown in the air from water bodies or wet areas.
        (vii) A fire in or near a gas appliance or piping.
        (viii) Unusual noise at an appliance.
        (ix) Unusual behavior of the flame at an appliance burner.
    (2) Response to a pipeline leak or emergency.
        (i) Importance of reporting any odor of gas no matter how slight.
        (ii) Report an odor or emergency to the system operator.
        (iii) Report pipeline damage that results in a release of gas to the local 911 or, where there is no local 911, to the local emergency response agency. In addition, consider providing information to excavators advising them of their responsibilities for reporting damage according to the PIPES Act of 2006 (49 USC 60114(d)).
        (iv) Actions to take until the operator can respond. These might include the following.
            (A) Do not attempt to locate gas leaks.
            (B) Do not remain in the building when there is a strong gas odor, and tell other occupants to evacuate.
            (C) Do not turn lights on or off or unplug electrical appliances when there is a strong gas odor.
            (D) Do not use telephones in the area of a strong gas odor.
            (E) Do not use elevators.

(F) Do not attempt to operate a valve on a main.
(G) Do not position or operate vehicles or powered equipment where leaking gas may be present.
(H) Do not smoke or use lighters, matches, or other open flames.
(I) Notify the local emergency response agency, such as the fire or police department (call 911 where applicable), regarding the emergency situation if gas leakage is determined to be significant (blowing or burning).

(d) Priority to protect life.
Emphasize that personal safety and the protection of human life should always be given higher priority than protection of property.
(e) Damage prevention.
See 2.5 of the guide material under §192.614.

*2.4 Additional information.*

Distribution, transmission, gathering, and underground storage operators may choose to include additional messages for preventing, recognizing, and reporting types of hazards or potential hazards not addressed by API RP 1162, such as the following.

(a) Heavy snow accumulation on meter set assemblies and a safe method of snow removal from meter set assemblies to prevent equipment damage (e.g., use of a broom instead of a shovel).
(b) Snow or ice falling or being shoveled from roofs onto gas facilities.
(c) Ice buildup on regulators or regulator vents.
(d) Carbon monoxide hazards from snow and ice buildup around combustion air and exhaust vents for gas appliances.
(e) Flooding that might affect gas facilities.
(f) Possibility of cross bores when sewer clearing activities are being conducted.
(g) Non-leaking damage to pipelines and other facilities.
(h) Damage to pipe surface, pipe wrap, or pipe coating due to scrapes or gouges.

*2.5 Message delivery methods.*

Guidance is provided in API RP 1162, Section 5 for several delivery methods and tools available for communicating with the stakeholder audiences. See 2.4 of the guide material under §192.614 for additional information regarding delivery methods for excavators and the affected public. However, the operator is required by §192.616(c) to justify in its program or procedural manual if it does not follow the general program recommendations of API RP 1162 regarding message delivery methods.

## 3 LANGUAGE

The following may provide indications of languages in addition to English to consider when conducting public education programs.

(a) Languages prescribed by state or local governments.
(b) Commercial non-English radio, television, and print media.
(c) U.S. Census data.

## 4 PROGRAM EFFECTIVENESS EVALUATION

See Guide Material Appendix G-192-3.

## 5 REFERENCES

(a) Information regarding public education programs, such as FAQs and Workshops, is available at https://primis.phmsa.dot.gov/comm/PublicAwareness/PublicAwareness.htm.
(b) OPS Advisory Bulletins (see Guide Material Appendix G-192-1, Section 2) as follows.
(1) ADB-93-01 (58 FR 7034, Feb. 3, 1993).

(2) ADB-97-01 (Issued in Kansas City, MO on Jan.24, 1997).
(3) ADB-08-03 (73 FR 12796, Mar. 10, 2008).
(4) ADB-11-02 (76 FR 7238, Feb. 9, 2011).

# §192.617

## Investigation of failures and incidents.

*[Effective Date: 11/12/70]*

**(a) *Post-failure and incident procedures*. Each operator must establish and follow procedures for investigating and analyzing failures and incidents as defined in §191.3, including sending the failed pipe, component or equipment for laboratory testing or examination, where appropriate, for the purpose of determining the causes and contributing factor(s) of the failure or incident and minimizing the possibility of a recurrence.**

***(b) Post failure and incident lessons learned.* Each operator must develop, implement, and incorporate lessons learned from a post-failure or incident review into its written procedures, including personnel training and qualification programs, and design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.**

**(c) *Analysis of rupture and valve shut-offs*. If an incident on an onshore gas transmission pipeline or a Type A gathering pipeline involves the closure of a rupture-mitigation valve (RMV), as defined in §192.3, or the closure of alternative equivalent technology, the operator of the pipeline must also conduct a post-incident analysis of all the factors that may have impacted the release volume and the consequences of the incident and identify and implement operations and maintenance measures to prevent or minimize the consequences of a future incident. The requirements of this paragraph (c) are not applicable to distribution pipelines or Types B and C gas gathering pipelines.**
**The analysis must include all relevant factors impacting the release volume and consequences, including, but not limited to, the following:**

**(1) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the incident;**

**(2) Appropriateness and effectiveness of procedures and pipeline systems, including supervisory control and data acquisition (SCADA), communications, valve shut-off, and operator personnel;**

**(3) Actual response time from identifying a rupture following a notification of potential rupture as defined at §192.3, to initiation of mitigative actions and isolation of the pipeline segment, and the appropriateness and effectiveness of the mitigative actions taken;**

**(4) Location and timeliness of actuation of RMVs or alternative equivalent technologies; and**

**(5) All other factors the operators deems appropriate.**

**(d) *Rupture post-failure and incident summary*. If the failure or incident on an onshore gas transmission pipeline or a Type A gathering pipeline involves the identification of a rupture following a notification of potential rupture, or the closure of an RMV (as those terms are defined in §192.3), or the closure of an alternative equivalent technology, the operator of the pipeline must complete a summary of the post-failure or incident review required by paragraph (c) of this section within 90 days of the incident, and while the investigation is pending, conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. The final post-failure or incident summary, and all other reviews and analyses produced under the requirements of this section, must be reviewed, dated, and signed by the operator's appropriate senior executive officer. The final post-failure or incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline. The requirements of this paragraph (d) are not applicable to distribution pipelines or Types B and C gas gathering pipelines.**

**[Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

**GUIDE MATERIAL**

*Note*: Although not required, operators should consider developing written procedures for failure investigations on Type B gathering lines.

## 1 GENERAL

(a) Data on all failures and leaks should be compiled to support compliance with §192.613. A failure investigation should be performed to determine the cause of the failure and minimize the possibility of a recurrence.
(b) For information on failures of PE pipe, see 3 of the guide material under §192.613.
(c) For information on reporting failures of mechanical fittings, see guide material under §191.12.

## 2 TYPES AND NATURE OF FAILURES THAT SHOULD BE ANALYZED

Failure investigation should be conducted for incidents as defined in §191.3. An operator should also consider investigating any other failure that enables the operator to establish patterns that might be occurring on its pipeline system. For examples, see guide material under §192.613.

## 3 FAILURE INVESTIGATION

(a) Failure investigation and subsequent analysis should determine the root cause(s) of the failure. The investigation may be as simple as assembling an internal review group or as complex as conducting a full-scale failure investigation with laboratory analysis of a failed component. The information for completing a 30-day incident report form contained in Part 191 may constitute an adequate analysis of a reportable failure or leak. See §§191.9 and 191.15.
(b) The general process for performing root-cause analysis is as follows.
  (1) Assemble the review team.
  (2) Define the problem and gather data and documentation.
  (3) Identify factors that contributed to the problem (i.e., causal factors).
  (4) Find the root cause for each causal factor, such as people, equipment, material, process, or outside influence.
  (5) Develop and assign recommendations.
  (6) Distribute recommendations and review the operator's procedures.
  (7) Implement the recommendations.
(c) For failures of mechanical fittings or joints, consider following the evaluation steps in 3 of the guide material under §191.12.

## 4 RESPONSE TO FAILURE

If a detailed analysis is to be made, rapid response will be necessary for preserving the integrity of specimens and gathering information.

## 5 DATA COLLECTION

5.1 *Incident.*
When a detailed analysis is to be made, a person at the scene of the incident should be designated to coordinate the investigation. That person's responsibilities should include the following.
(a) Acting as a coordinator for all field investigative personnel.
(b) Maintaining a log of the personnel, equipment, and witnesses.
(c) Recording in chronological order the events as they take place.
(d) Ensuring that photographs are taken of the incident and surrounding areas. These photographs may be of great value in the investigation.
(e) Ensuring the notification of all appropriate governmental authorities.
(f) Ensuring the preservation and chain of custody of evidence.

5.2 *Other failures.*
(a) Gather sufficient data to complete the general process for performing root-cause analysis. See 3

above.

(b) For a failure that does not elevate to the level of an incident, an operator may follow the data collection steps. See 5.1 above.

## 6 INVESTIGATION

A subject matter expert (SME) individual or team can perform an extensive evaluation or a more simplified evaluation based on the nature of a system and its operation. The SME should be knowledgeable by training or experience in the procedures for the investigation of an incident or other failure.

*6.1 Incident.*

When a detailed analysis is to be made, an SME investigation team should be designated. The investigation should include the following.

(a) Determination of the probable cause.
(b) Evaluation of the initial response.
(c) The need for system improvements, if necessary.
(d) The need for improvements in response, management, and investigation.

*6.2 Other failures.*

Assign an internal SME individual or team.

*6.3 Evaluation*

Consider testing the involved facilities, performing a leak or other survey of the involved area, or inspecting for signs of recent excavation activity.

## 7 SPECIMENS

As used in this section, a *specimen* is any physical evidence such as a pipe, joint, fitting, meter, other material, soil, or other sample that may be collected as part of a failure investigation.(a) Procedures for excavating the area over and around the specimen at the failure location should include precautions such as hand digging, vacuum excavation, or other appropriate methods to avoid causing damage to any potential specimen, pipelines in the vicinity of the excavation near the specimen, or the surrounding environment.

(b) Procedures should be prepared for selecting, collecting, preserving, labeling, and handling of specimens.
(c) Procedures for collecting plastic or metallurgical specimens should include precautions against changing the granular structure in the areas of investigatory interest (e.g., avoid heat effects from cutting and outside forces due to tools and equipment).
(d) Procedures may be necessary for proper sampling and handling of soil and groundwater specimens where corrosion may be involved.
(e) Procedures controlling the cutting, cleaning, lifting, identifying, and shipping of pipe specimens should be considered for preservation of valuable evidence on the pipe surface, and on any tear surface or fracture face, including making cuts far enough from the failure to avoid damaging critical areas of the specimen.
(f) The number of specimens needed to be collected at the failure site may vary depending on the type and number of tests anticipated. A series of independent or destructive tests may require multiple specimens. If there is a need to confirm the pipe material specifications, then additional pipe specimens should be obtained near the failure, but in an area of the piping where the physical properties and characteristics are unaffected by the failure itself. Other investigatory procedures may be utilized to confirm pipe material specifications.

## 8 TESTING AND ANALYSIS

(a) Recognized standard destructive and nondestructive techniques are the preferred means to examine test specimens. The testing methods used should be suited to the particular material being tested, and be pertinent to the failure investigation.
(b) Analysis and data on failures should be compiled and reviewed.

(c) The need for continuing surveillance of pipeline facilities should be determined. See guide material under §192.613.

## 9 REFERENCE

(a) NFPA 921, "Guide for Fire and Explosion Investigations."

# §192.619

## Maximum allowable operating pressure: Steel or plastic pipelines.

*[Effective Date: 03/12/21]*

**(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) 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 pipeline 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 Table 1 to paragraph (a)(2)(ii):**

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

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

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

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

**(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 |
|---|---|---|
| (i) Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006. | March 15, 2006, or date line becomes subject to this part, whichever is later. | 5 years preceding applicable date in second column. |
| (ii) Onshore regulated gathering pipeline (Type C under § 192.9(d)) that first became subject to this part (other than § 192.612) on or after May 16, 2022 | May 16, 2023, *or date pipeline becomes subject to this part, whichever is later* | 5 years preceding applicable date in second column. |
| (iii) Onshore transmission line that was a gathering pipeline not subject to this part before March 15, 2006. | March 15, 2006, or date pipeline becomes subject to this part, whichever is later | 5 years preceding applicable date in second column. |
| (iv) Offshore gathering lines. | July 1, 1976. | July 1, 1971. |
| (v) All other pipelines. | July 1, 1970. | July 1, 1965. |

**(4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with § 192.607, if applicable, and the history of the pipeline segment, including known corrosion and 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 instances:**

**(1) 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.**

**(2) For any Type C gas gathering pipeline under §192.9 existing on or before May 16, 2022, that was not previously subject to this part and the operator cannot determine the actual operating pressure of the pipeline for the 5 years preceding May 16, 2023, the operator may establish MAOP using other criteria based on a combination of operating conditions, other tests, and design with approval from PHMSA. The operator must notify PHMSA in accordance with §192.18. The notification must include the following information:**

**(i) The proposed MAOP of the pipeline;**

**(ii) Description of pipeline segment for which alternative methods are used to establish MAOP, including diameter, wall thickness, pipe grade, seam type, location, endpoints, other pertinent material properties, and age;**

**(iii) Pipeline operating data, including operating history and maintenance history;**

**(iv) Description of methods being used to establish MAOP;**

**(v) Technical justification for use of the methods chosen to establish MAOP; and**

**(vi) Evidence of review and acceptance of the justification by a qualified technical subject matter expert.**

**(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).**

**(e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624.**

**(f) Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (a) through (e) of this section as follows:**

**(1) Operators of pipelines in operation as of July 1, 2020 must retain any existing records establishing MAOP for the life of the pipeline;**

**(2) Operators of pipelines in operation as of July 1, 2020 that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with § 192.624, must retain the records reconfirming MAOP for the life of the pipeline; and**

**(3) Operators of pipelines placed in operation after July 1, 2020 must make and retain records establishing MAOP for the life of the pipeline.**

**[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976 with Amdt. 192-27A, 41 FR 47252, Oct. 28, 1976; Amdt. 192-30, 42 FR 60146, Nov. 25, 1977; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-102, 71 FR 13289, Mar. 15, 2006; Amdt. 192-103, 71 FR 33402, June 9, 2006; RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; Eff. date stayed by 73 FR 72737, Dec. 1, 2008; Amdt 192-125, Oct. 1, 2019, Amdt 192-128, Amdt. 192-129, 86 FR 63294 Nov. 15, 2021]**

## GUIDE MATERIAL

(a) Before adjusting the operation of a pipeline by increasing pressure within the limits of the pipeline segment's MAOP, but substantially above a historical long-term operating pressure, the operator should consider a review of the operating, maintenance, and testing history for the segment. See guide material under §§192.555 and 192.557. Pressure should be increased gradually at an incremental rate. The operator should consider conducting a leak survey when the pressure increase is concluded.

(b) Gathering lines constructed of non-listed (§192.7 and Appendix B to Part 192) materials may have an MAOP established by grandfather clause under §192.619(c).

(c) When pipe segments with the following characteristics are considered for flow reversal or service conversion, caution should be exercised if pressure testing is planned.

(1) Grandfathered pipelines that operate without a Subpart J pressure test or where sufficient historical test or material strength records are not available.

(2) Low frequency electric resistance welded (LF-ERW) pipe, lap welded pipe, pipe with unknown seam types, and pipe with seam factors less than 1.0, as defined in §192.113.

(3) Pipelines with a history of failures and leaks, especially those due to stress corrosion cracking (SCC), internal or external corrosion, selective seam corrosion (SSC), or manufacturing defects.

(4) Pipelines that operate above Part 192 design factors (i.e., above 72% SMYS per §192.619(c)).

(d) See Guide Material Appendices G-192-9, G-192-9A, and G-192-10.

## §192.620

## Alternative maximum allowable operating pressure for certain steel pipelines.

*[Effective Date: 10/01/15]*

**(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:**

**(i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated.**

**(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;**

**(iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;**

**(iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;**

**(v) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.712.**

**(vi) Operational monitoring procedures**

**(vii) Methodology and criteria used to justify and establish the MAOP; and**

**(viii) Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.**

**[Amdt. 192-125, Oct 1, 2019]**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-125.*

## §192.625

## Odorization of gas.

*[Effective Date: 10/15/03]*

**(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.**

**[Amdt. 192-2, 35 FR 17335, Nov. 11, 1970; Amdt. 192-6, 36 FR 25423, Dec. 31, 1971; Amdt. 192-7, 37 FR 17970, Sept. 2, 1972; Amdt. 192-14, 38 FR 14943, June 7, 1973; Amdt. 192-15, 38 FR 35471, Dec. 28, 1973; Amdt. 192-16, 39 FR 45253, Dec. 31, 1974; Amdt. 192-21, 40 FR 20279, May 9, 1975; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-76, 61 FR 26121, May 24, 1996 with Amdt. 192-76 Correction, 61 FR 36825, July 15, 1996; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]**

## GUIDE MATERIAL

## 1 GATHERING LINES

Operators of Type A gathering lines must evaluate the need for odorization according to §192.625(b) (§192.9(c)). Type B gathering lines are exempt from odorization requirements (§192.9(d)).

## 2 LATERAL LINE DEFINITION (§192.625(b)(3))

*Lateral line (transmission)* is a pipeline that branches from the main line or trunk of the transmission system, as determined by the operator, for the purpose of transporting gas to one or more distribution centers or to one or more large volume customers.

## 3 PERIODIC SAMPLING (§192.625(f))

*3.1 Sites*.

(a) Sampling sites should be selected to ensure that all gas within the piping system contains the required odorant concentration. The number of sites selected depends upon the size and configuration of the system, location of gate stations and locations suspected of low odorant level within the system.

(b) Consider the need for additional sampling sites when portable compressed natural gas (CNG) is temporarily introduced into the pipeline system. The type of processes used to produce CNG may cause the odorant level in the CNG to be reduced.

*3.2 Frequency*.

The testing should be performed at sufficiently frequent intervals to ensure that the gas is odorized to the required level.

*3.3 Tests*.

(a) Odor concentration tests should be conducted by personnel having a normal sense of smell and trained in the operation and use of odor concentration meters and procedures. A reference for determining odor intensity of natural gas is ASTM D6273.

(b) Sniff tests are qualitative tests that should be performed by individuals with a normal sense of smell. Such tests should be conducted by releasing small amounts of gas for a short duration in a controlled manner to determine whether odorant is detectable.

(c) A normal sense of smell may be affected by smoking, eating spicy foods, chewing tobacco or gum, or the presence of other strong odors. It may also be affected by health-related conditions, such as a head cold, that may interfere with the sense of smell. Prolonged or repetitive exposure to gas should be avoided because the sense of smell will fatigue with extended exposure to odorant.

(d) A program should be considered to periodically check personnel who perform odorant sampling to verify that they possess normal olfactory senses.

(e) A chemical analysis instrument (e.g., gas chromatograph) may be used to support or supplement odorant level information. If a chemical analysis instrument is used, the operator should periodically validate the measured odorant concentration with the proper concentration, which must be determined separately in accordance with paragraph (a) above.

*3.4 Records*.

(a) The operator should retain records of the odor level and odorant concentration test results.

(b) Operators of master meter systems who do not perform odorant level testing should retain their own records of sniff testing and records received from gas suppliers.

(c) Records of sniff testing should include the name of the person conducting the test, the date and location of the test, and whether odorant was detected.

## 4 ODOR INTENSITY IN PIPELINES

(a) New or replaced pipeline systems can react with or adsorb odorant, which could reduce the odor intensity. A method to minimize this effect is to temporarily increase odorant injection rates until the odor intensity reaches the desired level.

(b) Operators may consider informing plumbers and construction trades about odor reduction (see guide material under §192.629).

## 5 ODORANTS IN PLASTIC PIPELINES

Odorants should be introduced into plastic pipelines only in the vapor state, unless it has been determined by investigation or test that the kind of plastic is adequately resistant to direct contact with the liquid odorant.

## 6 SPECIAL CONSIDERATIONS

Operators should evaluate odorization requirements when transmission lines are subject to flow reversal.

## 7 REFERENCES

(a) AGA XQ0005, "Odorization Manual."

(b) ASTM D6273, "Standard Test Methods for Natural Gas Odor Intensity."

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# §192.627

## Tapping pipelines under pressure.

*[Effective Date: 11/12/70]*

**Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.**

### GUIDE MATERIAL

### 1 PERSONNEL QUALIFICATIONS

(a) Personnel performing hot taps should be:
   (1) Familiar with the pressure limitations of the hot tapping equipment to be used; and
   (2) Thoroughly trained in the mechanical procedures and safety precautions associated with the use of such equipment.
(b) Operators should consider using their Operator Qualification Program to establish tapping qualification criteria and documentation requirements for an individual's qualification.
(c) Although not required, operators of Type B gathering lines should consider the need for qualified personnel while performing hot taps on existing pipelines.

### 2 IDENTIFICATION OF PIPE

The operator should accurately identify the line to be tapped. Special caution should be exercised when other underground facilities are known or suspected to be in the area. Special caution should also be exercised when personnel locating the line to be tapped are unfamiliar with the area. The operator's personnel should be familiar with the piping materials used by other utilities in the area, such as steel, plastic, and cast iron.

*2.1 Before tapping.*
(a) Maps and records. The operator should thoroughly review applicable maps and records and contact the operators of other underground facilities (e.g., one-call system) to determine the location of other lines that may be in the vicinity of the pipeline to be tapped.
(b) Exposed pipe. The following factors may be used to ensure that the exposed pipe is the one to be tapped. When identification of the pipe is uncertain, the operator should consider extending the excavation.
   (1) Outside diameter.
   (2) Longitudinal weld characteristics.
      (i) Electric resistance weld.
      (ii) Electric flash weld.
      (iii) Electric fusion/submerged arc weld.
      (iv) Spiral weld.
      (v) Seamless.
      (vi) Other weld characteristics.
   (3) Coating.
      (i) Coal tar.
      (ii) Asphalt.
      (iii) Wax.
      (iv) Thin-film.
      (v) Tape.
      (vi) Extruded mastic or similar material.
      (vii) Other coating materials.
      (viii) Bare.

(4) Material.
    (i) Steel.
    (ii) Cast iron.
    (iii) Plastic.
    (iv) Non-industry proprietary pipe.
(5) Joint connections.
    (i) Welded.
    (ii) Mechanically coupled.
    (iii) Threaded.
    (iv) Bell and spigot (lead, cement, or other) joint.
    (v) Fused.
    (vi) Solvent cement.
    (vii) Other.
(6) Manufacturers markings.
(7) Color.
(8) Surface finish.
(9) Pipe-to-soil potential (off/on rectifier, test leads, and bonds).
(10) Wall thickness (ultrasonic).
(11) Pipe temperature.

(c) Unexposed pipe. The following may be used to further ensure identification of the pipe to be tapped.
(1) Pipe locator tracing.
(2) Probing.
(3) Above-ground indications of other buried facilities, such as markers, valve settings, backfill, and painted fence posts.
(4) Field alignment.

2.2 *During tapping.*

During the tapping procedure, the operator should address the following.

(a) On initial line perforation:
(1) Verify pressure.
(2) Verify line contents, such as odorized gas, oil, gasoline, or water.
(b) Inspect recovered coupon.

2.3 *Special considerations for casings and insertions*.

The operator should check for the presence of vents that would indicate the existence of a casing. If observations (e.g., records, vents, variance in diameter) indicate the possibility of a casing or insertion, the operator should consider radiography or checking for the existence of a depressured annulus (with tapping machine or by other means).

## 3 SUITABILITY FOR TAPPING

The operator should consider the following to determine the suitability of the pipe and the proposed location for tapping.

(a) Inspect pipe for external corrosion.
(b) Determine internal defects with ultrasonic meter or radiography.
(c) Verify proper tap / seam / joint relationships.
(d) Verify tapping equipment and materials are correct for intended pressure service.
(e) Determine the proximity to regulators, valves, relief valves, meters, and other equipment that might be affected by metal shavings or other materials that are deposited into a pipeline during tapping operations. When in close proximity, the operator should consider using a magnetic sweep to collect metal shavings or installing a filter or screen. See §192.739(a)(4) for additional information.

## 4 LOW-HYDROGEN WELDING

Consideration should be given to the use of a low-hydrogen welding procedure when welding on a steel pipeline in service where the flow of gas or the metal thickness does not allow for maintaining adequate welding temperature.

## §192.629
## Purging of pipelines.

*[Effective Date: 11/12/70]*

**(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.**

### GUIDE MATERIAL

*Note*: Although not required, operators of Type B gathering lines should consider the use of written purging procedures.

### 1 PURGING INSIDE BUILDINGS

(a) If a service line terminates indoors and purging is necessary, its contents should be vented to an unconfined outside location using tubing, hose, or other means. Service lines and customer piping served by low pressure, where the volume is small and the purging will not constitute a hazard, may be purged indoors as follows.
  (1) Through an appliance burner equipped with a continuous source of ignition, or
  (2) Monitoring the discharge point of the purge with a combustible gas indicator and stopping the purge as soon as gas is detected.
(b) The gas should not be purged into a confined space or area where there is an ignition source. Personnel should ensure there is adequate ventilation and control the purging rate.
(c) Metallic components of purge lines should be grounded to prevent a static electrical discharge. See guide material under §192.751.

### 2 NOTIFICATIONS

(a) Operators may consider including information on purging interior gas piping directly to the outside in public awareness messages or communications with plumbers and construction trades.
(b) For notification of public officials and the public in the vicinity of purge or discharge, see 4 of the guide material under §192.751.

### 3 SERVICE LINES WITH EXCESS FLOW VALVES (EFV)

For service lines containing an EFV, see guide material under §192.381 for purging considerations.

### 4 REFERENCES

(a) AGA XK1801, "Purging Manual."
(b) NFPA 54/ANSI Z223.1, "National Fuel Gas Code."

# §192.631

## Control room management.

*[Effective Date: 03/24/17]*

**(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.**

**[Issued by Amdt. 192-112, 74 FR 63310, Dec. 3, 2009 with Amdt. 192-112 Correction, 75 FR 5536, Feb. 3, 2010; Amdt. 192-117, 76 FR 35130, June 16, 2011; Amdt. 192-123, 82 FR 7998, Jan. 23, 2017]**

## GUIDE MATERIAL

## 1 GENERAL

(a) Section 192.631 applies to any operator of a pipeline (facility) that uses a control room and controllers to monitor and control at least some of those pipeline facilities remotely through a Supervisory Control and Data Acquisition (SCADA) system. An operator is required to have written plans that cover all of the components listed in the sections below.

(b) Certain operators are required to develop the appropriate procedures to comply with only fatigue mitigation (§192.631(d)), compliance validation (§192.631(i)), and compliance and deviation (§192.631(j)).

(c) Operators of Type A gathering lines need to determine the applicability of control room management under §192.631 (§192.9(c)). The requirements of this section do not apply to Type B gathering lines (§192.9(d)).

(d) When determining the number of services under the oversight of a control room, the total should equal the number of services that are served by a single control room as reported to PHMSA-OPS on the annual report (§191.11).

(e) A single control room that oversees the following may be required to meet all of the requirements of §192.631.

(1) Several distribution systems having an aggregate total of 250,000 services or more at any one time.
(2) Several transmission systems and any one of the systems has a compressor station.
(3) A transmission system that has a compressor station and a distribution system of less than 250,000 services.
(4) A distribution system of 250,000 services or more and a transmission system that does not have a compressor station.

(f) Where an operator has several control rooms that oversee distinct distribution systems and each control room oversees a system of less than 250,000 services, the operator is only required to comply with the fatigue mitigation, compliance validation, and compliance and deviation requirements of §192.631(a)(1).

(g) An operator may already have many of the required components as either written or unwritten procedures. Existing procedures, such as those required by §§192.605 and 192.615, may be modified to meet the additional requirement of control room management, and unwritten procedures should be documented. The operator should verify that there are no conflicts between new control room management procedures and existing procedures.

## 2 CONTROLLER

(a) A controller is a person who monitors and controls pipeline operations from a control room (see §192.3). Monitoring the pipeline means the person reviews real-time or near real-time operational information such as pressures and flows via a SCADA system. Controlling the pipeline is the ability to change pressures or flows via a SCADA system or by contacting someone else to make the change in the field.

(b) Many compressor stations have what is often referred to as a control room. This is a place where station operators monitor the station operation, but may also control the pipeline operations in and out of the station. An operator should review the function of these remote control rooms to determine if personnel are actually serving as controllers. If these remote persons are not authorized to make changes without confirmation from the central control room, they should not be considered controllers.

(c) An individual who accesses the SCADA system for other incidental business purposes such as monitoring, commercial reasons, customer information, or general information should not be considered a controller.

(d) A person in a 24-hour manned location (e.g., police station, 911 center) should not be considered a controller under §192.631, especially for small gas systems, where that person:

(1) does not use a computer-type interface with a keyboard or mouse and a display screen (or touch-controlled screen);
(2) is charged with watching a gauge or light without understanding the implications; or
(3) is only provided with specific instructions as to whom to contact when certain changes are noted.

## 3 COMPONENTS OF CONTROL ROOM MANAGEMENT PROCEDURES

*3.1 General.*

(a) Controllers of gas systems have a wide variety of roles due to the differences and complexities of various gas systems. Transmission system control functions may be primarily focused on moving gas from Point A to Point B. Distribution system control functions may be primarily focused on maintaining adequate pressures and flows for end-use consumers. Control room management procedures should be tailored to the specific type of system.

(b) Procedures can be existing procedures that are modified to meet the prescribed requirements of §192.631.

(c) The control room management procedures should complement the operator's existing procedural manual for operations, maintenance, and emergencies.

*3.2 Controller roles and responsibilities.*

Section 192.631(b) requires operators to define the roles and responsibilities of the controller during normal, abnormal, and emergency operating conditions. This section also requires operators to define the roles, responsibilities, and qualifications of others authorized to direct or supersede the actions of the controller.

(a) Normal operating conditions.
  (1) Types of normal operating conditions might include the following.
    (i) Gas flow control and monitoring.
    (ii) Gas pressure control and monitoring.
    (iii) Equipment operation and monitoring.
    (iv) System requirements and monitoring.
    (v) Start/stop of compressor stations to meet system requirements.
    (vi) Gas delivery schedule adjustments.
    (vii) Gas storage monitoring.
    (viii) Interconnects and delivery nominations.
    (ix) Pressure set-point adjustments.
    (x) Activation or deactivation of pipelines for routine operations.
    (xi) Pigging operations.
    (xii) Notifications to field personnel.
  (2) Procedures should contain the following.
    (i) A description of normal operating conditions.
    (ii) A clear definition of the controller's authority over normal system operations. Consideration should be given to the responsibilities that could be within a controller's range of authority, without requiring any supervisory oversight or approval.
    (iii) A communication protocol should designate who a controller should notify and what information the controller should provide during normal operational changes. This could be as simple as a log, or could rely on computerized records to note the changes. The communication protocol should define the required communications between the control room and field operations personnel.
    (iv) Recordkeeping requirements for controller shift changes.

(b) Abnormal operating conditions.
  (1) Types of abnormal operating conditions might include the following.
    (i) Loss of communication between the SCADA display and a field device.
    (ii) An operable field device that does not respond to a SCADA command.
    (iii) An unexpected shutdown of field equipment, such as a compressor engine.
    (iv) An unexpected closure of a valve.
    (v) Pressure exceeding MAOP or pressure limits.
    (vi) Pressure falling below delivery requirements.
    (vii) False or abnormal readings.
    (viii) High-high alarms.
    (ix) Activation of a safety device, such as a relief valve.
    (x) Emergencies on connecting pipelines.
    (xi) Any other malfunction of a component, deviation from normal operation, or personnel error which may result in a hazard to persons or property as defined by the operator.
    (xii) For transmission operators, events defined by the requirements of §192.605(c).
  (2) Procedures should contain the following.
    (i) A description of operations that would constitute an abnormal operating condition or situation.
    (ii) Actions that should be taken by a controller upon becoming aware of an abnormal operating condition.
    (iii) A definition of roles, responsibilities, and actions that a controller may take without supervisory approval. All actions should be to protect people first and then property.
    (iv) A communications protocol that designates, upon a controller becoming aware of an

abnormal situation, who that controller should notify and what information should be provided. The protocol should include communication requirements for an abnormal situation discovered by the controller or by field personnel. Information regarding the situation should be recorded and include the persons notified and the information provided.

(v) Recordkeeping requirements for these abnormal situations for further review and training purposes as specified in 7 below. (Transmission operators should already have recordkeeping requirements in place per §192.605(c)).

(c) Emergency operating conditions.

(1) Types of emergency operating conditions might include the following.

(i) Overpressurization.

(ii) Low pressure.

(iii) Sudden pressure drop.

(iv) Activation of an emergency shutdown (ESD) device.

(v) Report of blowing gas, fire, or explosion.

(vi) Weather-related events, such as flooding, tornado, or hurricane causing damage to a pipeline facility.

(vii) Hazardous leak.

(viii) Report of gas in a building and emergency evacuation.

(2) Procedures should contain the following.

(i) A description of operations that would constitute an emergency operating condition or situation.

(ii) Actions that should be taken by a controller upon becoming aware of an emergency situation. (These emergency situations may be partially addressed in the operator's Emergency Plan.)

(iii) A definition of roles, responsibilities, and actions that a controller may take without supervisory approval. All actions should be to protect people first and then property.

(iv) A communications protocol that designates, upon a controller becoming aware of an emergency situation, who that controller should notify and what information should be provided. The protocol should include communication requirements for an emergency situation discovered by the controller or field personnel. Information regarding the situation should be recorded and include the persons notified and the information provided.

(v) Required communications and approvals needed before returning to normal operations.

(vi) Recordkeeping requirements for these events for further review and training purposes as specified in 7 below. Recordkeeping requirements for reportable incidents may be addressed with written procedures for §§191.9 or 191.15.

*3.3 Communications.*

Communication issues may also be addressed in management of change (MOC) and training in 6 and 7 below.

(a) Communication protocols.

Consideration should be given to the timeliness, type, and amount of information to be passed on to both internal and external entities, and designation of the person responsible for the communication. Internal entities may include other controllers, both on shift and between shifts, and other operator personnel outside of the control room environment such as field technicians, supervisors, and management. External entities may include suppliers, customers, local emergency personnel, the National Response Center (NRC), or regulatory agencies.

(b) Control room shift change communication.

Shift change communications should not be limited to scheduled changeovers, but should also include emergency and unanticipated changes due to illnesses, personal emergencies, routine breaks, and meals. Shift change communications may need to be tailored for those control rooms that do not operate on a continuous 24-hour basis.

(c) Procedures should contain the following.

(1) A process to record shift changes between controllers, including names and times of changes. This can be a paper or electronic logbook, a SCADA system login, a checklist, or some other process.
(2) Information that is required to be passed on from the outgoing controller to the incoming controller, which might include the following.
  (i) Ongoing emergencies or abnormal operations.
  (ii) Upcoming pipeline operations that might occur during upcoming shifts.
  (iii) Routine operating information, such as flow, linepack, and customer requirements.
  (iv) Pipelines or facilities out of service, such as a storage field.
  (v) Maintenance activities.
  (vi) Pigging operations.
  (vii) Unusual flow conditions, such as pipelines with reduced MAOPs or gas quality issues.
  (viii) Weather-related events.
  (ix) Alarms or conditions being investigated.
  (x) Communication outages (e.g., no SCADA data) and manned locations.
  (xi) Other unusual operations.

(d) Other internal communications.
Communications procedures should define events that require communication between field operations or customer service and the control room. Communication becomes especially important prior to non-routine events. These events may include the following.
(1) Outages.
(2) Maintenance activities, including line blowdowns, service restoration, and storage fields going off and on line.
(3) Pigging operations.
(4) Starting/stopping compressor units.
(5) Changes in regulator set points.
(6) Variations in flow.
(7) Retired equipment going off line or new equipment being put into service.

(e) External communications.
Communications procedures should address and establish guidelines for dealing with first responder personnel, media or the public, especially during emergencies. Often the control room phone number is the emergency number posted on operator facilities. Depending on the number of calls per day, an operator may want to consider using non-controller personnel to handle the public communications or providing additional workers during emergency situations. The operator should consider the following in its external communications protocols.
(1) Determining the nature and priority of the contact.
(2) Providing additional information.
(3) Notifying appropriate operator personnel.
(4) Notifying emergency officials, if required.
(5) Notifying other external entities.
(6) Documenting communication and actions taken.

*3.4 Manual pipeline operation.*

(a) In the event that the SCADA system becomes non-operational, operators are required to have a communications plan in place to operate the pipeline manually (§192.631(c)(3)). The plan should include provisions to notify other operator personnel, with defined tasks for field personnel. The plan may be part of an emergency plan, incident plan, disaster plan, or similar to plans developed for the year 2000 problem (Y2K). The operator should consider items such as the following.
(1) Critical locations that need to be monitored.
(2) Means of communicating (e.g., landlines, texting, radios).
(3) Availability of workforce and call-out lists.
(4) Means of recording critical communications.
(5) Means of recording critical operational data.
(6) Frequency of communications.

(7) Approvals or oversight of operations.

(b) Section 192.631(c)(3) requires that operators test the manual operation communications procedure each calendar year. An operator may choose to perform the test as a single event or in multiple stages, depending on the operational requirements of the system. If an operator chooses to test in multiple stages, testing should ensure overlap of areas to confirm that all points within a pipeline system are included.

## 4 SUPERVISORY CONTROL AND DATA ACQUISITION SYSTEMS

*4.1 General.*

SCADA systems provide controllers with important tools to perform their roles and responsibilities. These tools include instrumentation for monitoring pipeline operating conditions and for operating pipeline equipment. SCADA systems may generate an alarm when an event has occurred or an unusual situation is developing.

The following are the primary components of a SCADA system, with definitions or examples of each.

(a) Field devices.
  (1) Pressure transmitters.
  (2) Temperature transmitters.
  (3) Flow computers or totalizers.
  (4) Gas chromatographs.
  (5) Gas stream analyzers (e.g., moisture, H2S).
  (6) Valve actuators.
  (7) Pressure regulator actuators.
  (8) Mechanical devices that control compressor engines.

  *Note:* Devices that lack communication capability with the control room, such as pressure recorders, gauges, or other field devices that only monitor the pipeline, are not considered part of SCADA.

(b) Data gathering and transmitting equipment.
  This equipment is comprised of computer hardware used to collect data from various field devices and format it for transmittal to a SCADA host computer, or receive and process instructions from a SCADA host computer. This equipment can also receive and process data from field devices and initiate pre-programmed instructions. An operator may choose how often data is transmitted to the system. Commonly used devices include the following.
  (1) Remote terminal units (RTUs).
  (2) Programmable logic controllers (PLCs).

(c) Communications processes.
  These are modes, protocols, and equipment used to transmit data between data-gathering equipment and the SCADA host computer. Modes of communication include the following.
  (1) Radio.
  (2) Wired phone (e.g., leased-line, dial-up, operator-owned).
  (3) Cellular.

(4) Intranet.
  (5) Internet.
  (6) Satellite.
  (7) Microwave.

(d) SCADA host computer and software.
  This processing or computing equipment and overlaying software programming is used to provide a link between the field or data-acquisition equipment and the controller interface.

(e) Controller interface.
  Equipment such as computer displays and human-machine interfaces (HMI) used by controllers to interact with field equipment or monitor the information gathered by the SCADA system.

(f) Data-acquisition equipment.
  Computer hardware and software used in conjunction with the SCADA system for storing historical

data.

(g) Recordkeeping.

A crucial part of the SCADA system is the recordkeeping function provided by the system. One component is how often information is received from the field. Acquired data is sent to a computer memory to be retained. Operators should consider data polling frequencies, the location of information on the pipeline system, and computer memory in determining how much information needs to be retained. Too much data may clog the system and allow a controller to miss critical pressure measurements. Too little data may lead to false conclusions. An operator may choose to vary the polling times based on factors such as the importance of the data, critical locations, and the need for up-to-date information to make decisions. The retained data is often used for flow analysis and efficiency studies, but is particularly important for reviewing abnormal operations, emergencies, and incidents.

(h) Section 192.631(c)(4) requires that backup SCADA systems are tested at least once each calendar year, but at intervals not to exceed 15 months. These tests may be done in conjunction with the annually required manual operation tests, or may be done separately.

*4.2 Controller interface.*

(a) Section 192.631(c)(1) requires the implementation of certain sections of API RP 1165 (see §192.7 for IBR), when changing or upgrading SCADA systems. If implementation of API RP 1165 is impractical, an operator should use sound engineering practices or safety analyses to explain why compliance is impractical or is unnecessary. The justification needs to be in writing (§192.631(j)). The justification should be included either in the procedures or in other suitable locations. The level of safety should be equal to or greater than that which would have been provided if the operator had followed API RP 1165.

(b) SCADA screen displays are the primary point of interaction between the controller and the pipeline system. Consideration should be given to the following when changing SCADA displays.
   (1) Amount of data shown on any screen at one time.
   (2) Summary screens for aggregating important data.
   (3) Navigational tools to minimize the number of controller actions (typically mouse clicks) to move between screens.
   (4) Highlighting the important data.
   (5) Location of data on the display.
   (6) Consistency of layouts, data locations, font types, and use of color and objects across multiple screens (objects are symbols on the screen that are used to represent field devices).
   (7) Differences between data that is shown in a normal operating state and data that is shown in an abnormal or alarm state.
   (8) Consistency of displays within a company.
   (9) Consistency of displays between a main control room and remote locations.

*4.3 Alarm management.*

(a) Alarms come in several different varieties. Most alarms notify the controller that an unusual condition exists on the pipeline or associated equipment. Some alarms notify the controller of a condition that may directly affect pipeline safety (e.g., high pressure). Some alarms may notify the controller of an abnormal condition on a piece of field equipment (e.g., low oil pressure on a compressor). Other alarms may notify the controller of a situation that does not affect pipeline safety (e.g., security alarms), but requires controller action. Every alarm that comes in through the SCADA system should require some type of controller action. However, some alarms may be informational and notify the controller that an automated process has initiated. Operators should consider the following.
   (1) Alarm prioritization (possibly providing another means to monitor alarms that are not associated with the safety and integrity of the pipeline).
   (2) Other control room tasks that could distract a controller from the SCADA display.
   (3) Configuring alarms that a controller will see to elicit a response by the controller.
   (4) Alarm response method (e.g., direct intervention by a controller, elevation to a higher

authority, simply logging the event)

(b) Each operator using a SCADA system is required to have a written alarm management plan that addresses each requirement of §192.631(e). The alarm management plan should contain the following.
   (1) Definition of each alarm that will be viewed by a controller and why the point is an alarm.
   (2) Parameters, such as set-point values, for each defined alarm.
   (3) Actions to be taken by the controller when an alarm is activated.
   (4) A method to log the following points affecting pipeline safety.
      (i) Alarms that have been temporarily inhibited.
      (ii) Alarms that have been permanently removed.
      (iii) Alarms that have provided false information.
      (iv) Alarms that have had forced or manual values.
   (5) Intervals for the alarm review.
   (6) A process for reviewing alarms and general activity directed to controllers. A review of points affecting pipeline safety that have been disabled, had alarms inhibited, or had forced or manual values must be performed monthly (§192.631(e)(2)). A review and verification of all alarms and set points should be done annually. If one part of a system has substantially more alarms than another, an operator may consider the redistribution of alarm responsibilities.
   (7) Recordkeeping requirements for the review processes.

(c) Operators that use a single controller on duty should develop a method to allow controllers to be notified of alarms while away from their console or desk.

*4.4 Point-to-point verification.*

(a) Section 192.631(c)(2) requires point-to-point verification between safety-related field devices and SCADA displays. This verification must be performed on changes made to SCADA displays, in addition to newly installed or modified field devices. The point-to-point verification generally involves a field technician at the site of the field device communicating with a controller (or other qualified person) and verifying that the value being transmitted by the field device matches the values being displayed on the SCADA screen, and that the data activates the alarm if outside the set parameters. Operators might consider performing point-to-point verifications annually or during regular calibration cycles. The verification plan should include written procedures that describe and record the verification process.

(b) Examples of safety-related field devices that might require point-to-point verification include the following.
   (1) Valve status indicators.
   (2) Pressure transmitters.
   (3) Flow-rate transmitters.
   (4) Compressor status indicators.
   (5) Emergency shutdown status.
   (6) Leak detection indicators.
   (7) RTU communication status indicators.

## 5 OPERATING EXPERIENCE

(a) An operator should periodically review relevant operating information to enhance the control room management plan. Reportable incidents (for definition, see §191.3) must be reviewed to determine if the following factors contributed to the incident (§192.631(g)(1)).
   (1) Controller fatigue.
   (2) Field equipment.
   (3) Control room procedures.
   (4) SCADA configuration and performance.
   (5) Operation of any relief device (for transmission facilities, the operation of a relief device should already be noted as an abnormal operation).

(b) Post-emergency reviews, as required by §192.615(b)(3), should examine whether controller actions contributed to the emergency. In addition to emergencies and reportable incidents, an operator should review abnormal operations (§192.605(c)), accidents, failure investigations (§192.617), root-cause investigations, or near misses as these might also provide valuable information. Any deficiencies or improvements noted during the review should be documented, and changes to the procedures should be implemented, if appropriate.

(c) The review procedure should specify the records needed to provide documentation of the incident reviews.

## 6 MANAGEMENT OF CHANGE (§192.631(f))

(a) Changes are regular occurrences during the course of pipeline operations requiring effective management through established processes and procedures. Operators should identify and document changes that might impact a controller's ability to monitor or control the pipeline facilities. Communications between the control room, management, and field personnel are a vital part of the control room MOC process. Operators should consider controller involvement when implementing the following changes to pipeline facilities.
   (1) Temporary interruption or limitation of gas flow (e.g., valve closure, pipeline shutdown).
   (2) Restoration of gas flow capability (e.g., valve opening, completion of maintenance outage).
   (3) Temporary limitation or restoration of control (e.g., compressor maintenance outage, regulator or city-gate station maintenance).
   (4) Temporary or permanent change in pipeline flow patterns (e.g., placing new pipeline facility in service, removing a pipeline from service, flow reversal).
   (5) Change in established MAOP due to regulatory oversight or integrity management limitation.
   (6) Purchase or sale of assets.
   (7) Change to existing equipment (e.g., valves, piping) or new equipment coming online.
   (8) Newly constructed facility (e.g., pipeline, compressor station, measurement or regulator station) being turned on line.
   (9) Converting an existing liquid pipeline to natural gas service
   (10) Procedural change affecting operations, maintenance, or safety.
   (11) Change to operating agreement.
   (12) Pigging or other maintenance activity.
   (13) Change to control systems or SCADA.
   (14) Emergency or abnormal situation.
   (15) Implementation of change resulting from the required reviews in 5 above.

(b) Information about planned changes (e.g., temporary flow patterns, new facilities, blow- down activities) to a controlled pipeline facility should be brought to the attention of the controller through direct planning involvement.

(c) An MOC plan for a control room may be a separate document, or an existing MOC process may be modified to address the requirements of a control room. An operator is encouraged to consolidate procedures, where possible, to reduce the number of potential conflicts between multiple documents.

## 7 TRAINING (§192.631(h))

The controller training program may include the following.

(a) Appropriate training for activities that would be considered covered tasks in the operator qualification (OQ) program.
   (1) An operator should continue to implement the OQ regulations (Subpart N) through the application of the four-part test for covered tasks. The operator should also determine whether any new tasks will be added to the OQ program when implementing control room management procedures. The operator should define both generic and specific covered tasks for controllers.

**(5) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.**

**(6) Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in §§ 192.713 and 192.933.**

**(d) *Defect remaining life.* If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with § 192.712.**

**(e) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.**

**[Issued by Amdt. 192-125, Oct. 1, 2019]**

## GUIDE MATERIAL

*This guide material is under review following Amendment 192-125.*

# §192.634

## Transmission lines: Onshore valve shut-off for rupture mitigation.

*[Effective Date: 10/05/2022]*

**(a) *Applicability*. For new or entirely replaced onshore transmission pipeline segments with diameters of 6 inches or greater that are located in high-consequence areas (HCA) or Class 3 or 4 locations and that are installed after March 31 2023, an operator must install or use existing rupture-mitigation valves (RMV), or an alternative equivalent technology, according to the requirements of this section and §§192.179 and 192.636. RMVs and alternative equivalent technologies must be operational within 14 days of placing the new or replaced pipeline segment into service. An operator may request an extension of 14-day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in §192.18, that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this section apply to all applicable pipe replacement projects, even those that do not otherwise involve the addition or replacement of a valve. This section does not apply to pipe segments in Class 1 or Class 2 locations that have a potential impact radius (PIR)m as defined in §192.903, that is less than or equal to 150 feet.**

**(b) *Maximum spacing between valves*. RMVs, or alternative equivalent technology, must be installed in accordance with the following requirements:**

**(1) *Shut-off Segment.* For purposes of this section, a "shut-off segment" means the segment of pipe located between the upstream valve closest to the upstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment and the downstream valve closest to the downstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment so that the entirety of the segment that is within the HCA or the Class 3 or Class 4 location is between at least two RMVs or alternative equivalent technologies. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream valves, the shut-off segment also must extend to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or Class 4 locations or HCA segments may be contained within a single shut-off segment. The operator is not required to select the closest valve to the shut-off segment as the RMV, as that term is defined in §192.3, or the alternative equivalent technology. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, but it must be able to be closed within 30 minutes following rupture identification, as that term is defined at §192.3. Such a valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with §192.18.**

**(2) *Shut-off segment valve spacing*. A pipeline subject to paragraph (a) of this section must have RMVs or alternative equivalent technology on the upstream and downstream side of the pipeline segment. The distance between RMVs or alternative equivalent technologies must not exceed:**

**(i) 8 miles for any Class 4 location,**
**(ii) 15 miles for any Class 3 location, or**
**(iii) 20 miles for all other locations.**

**(3) *Laterals*. Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all the laterals contributing gas volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment gas volume based upon maximum flow volume at the operating pressure. For laterals that are 12 inches in diameter or less, a check valve that allows gas to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction may be used as an alternative equivalent technology where it is positioned to stop flow into the shut-off segment. Such check valves that are used as an alternative equivalent technology in accordance with this paragraph are not subject to § 192.636,**

**but they must be inspected, operated, and remediated in accordance with § 192.745, including for closure and leakage to ensure operational reliability. An operator using such a check valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 192.18 and 192.179 develop and implement maintenance procedures for such equipment that meet § 192.745.**

**(4) *Crossovers*. An operator may use a manual valve as an alternative equivalent technology in lieu of an RMV for a crossover connection if, during normal operations, the valve is closed to prevent the flow of gas by the use of a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must develop and implement operating procedures and document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of gas. An operator using such a manual valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 192.18 and 192.179.**

**(c) *Manual operation upon identification of a rupture*. Operators using a manual valve as an alternative equivalent technology as authorized pursuant to §§192.18 and 192.179 must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shut-off in accordance with this section and §192.636. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to shut off all valves manually, not to exceed the maximum response time allowed under §192.636(b).**

**[Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

## GUIDE MATERIAL

*This guide material is under review following Amendment 192-130.*

# §192.635

## Notification of potential rupture.

*[Effective Date: 10/05/2022]*

**(a) As used in this part, a "notification of potential rupture" refers to the notification of, or observation by, an operator (e.g., by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline:**

**(1) An unanticipated or unexplained pressure loss outside of the pipeline's normal operating pressures, as defined in the operator's written procedures. The operator must establish in its written procedures that an unanticipated or unplanned pressure loss is outside of the pipeline's normal operating pressures when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less, unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in gas demand, gas receipts, or gas deliveries; or**

**(2) An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting paragraph (a)(1) of this section; or**

**(3) Any unanticipated or unexplained rapid release of a large volume of gas, a fire, or an explosion in the immediate vicinity of the pipeline.**

**(b) A notification of potential rupture occurs when an operator first receives notice of or observes an event specified in paragraph (a) of this section.**

**[Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-130.*

# §192.636

## Transmission lines: Response to a rupture; capabilities of rupture-mitigation valves (RMVs) or alternative equivalent technologies.

*[Effective Date: 10/05/2022]*

**(a) *Scope*. The requirements in this section apply to rupture-mitigation valves (RMVs), as defined in §192.3, or alternative equivalent technologies, installed pursuant to §§192.179(e), (f), (g), and 192.634.**

**(b) *Rupture identification and valve shut-off time.* An operator must, as soon as practicable but within 30 minutes of rupture identification (*see* § 192.615(a)(12)), fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of gas released from a pipeline and mitigate the consequences of a rupture.**

**(c) *Open Valves*. An operator may leave an RMV or alternative equivalent technology open for more than 30 minutes, as required by paragraph (b) of this section, if the operator has previously established in its operating procedures and demonstrated within a notice submitted under § 192.18 for PHMSA review, that closing the RMV or alternative equivalent technology would be detrimental to public safety. The request must have been coordinated with appropriate local emergency responders, and the operator and emergency responders must determine that it is safe to leave the valve open. Operators must have written procedures for determining whether to leave an RMV or alternative equivalent technology open, including plans to communicate with local emergency responders and minimize environmental impacts, which must be submitted as part of its notification to PHMSA.**

**(d) *Valve monitoring and operation capabilities*. An RMV, as defined in § 192.3, or alternative equivalent technology, must be capable of being monitored or controlled either remotely or by on-site personnel as follows:**

**(1) Operated during normal, abnormal, and emergency operating conditions;**

**(2) Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. For automatic shut-off valves (ASV), an operator does not need to monitor remotely a valve's status if the operator has the capability to monitor pressures or gas flow rate within each pipeline segment located between RMVs or alternative equivalent technologies to identify and locate a rupture. Pipeline segments that use manual valves or other alternative equivalent technologies must have the capability to monitor pressures or gas flow rates on the pipeline to identify and locate a rupture; and**

**(3) Have a back-up power source to maintain SCADA systems or other remote communications for remote-control valve (RCV) or automatic shut-off valve (ASV) operational status, or be monitored and controlled by on-site personnel.**

**(e) *Monitoring of valve shut-off response status*. The position and operational status of an RMV must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means. An operator does not need to monitor remotely an ASV's status if the operator has the capability to monitor pressures or gas flow rate on the pipeline to identify and locate a rupture.**

**(f) *Flow modeling for automatic shut-off valves*. Prior to using an ASV as an RMV, an operator must conduct flow modeling for the shut-off segment and any laterals that feed the shut-off segment, so that the valve will close within 30 minutes or less following rupture identification, consistent with the operator's procedures, and in accordance with §192.3 and this section. The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions that may be encountered during the year, not exceeding a period of 15 months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or gas receipt tie-ins. If operating conditions**

**change that could affect the ASV set pressures and the 30-minute valve closure time after notification of potential rupture, as defined at §192.3, an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with §192.745. The flow model must include a time/pressure chart for the segment containing the ASV if a rupture occurs. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could render the 30-minute valve closure time unachievable.**

**(g) *Manual Valves in non-HCA, Class 1 locations*. For pipeline segments in a Class 1 location that do not meet the definition of a high consequence area (HCA), an operator submitting a notification pursuant to §§192.18 and 192.179 for use of manual valves as an alternative equivalent technology may also request an exemption from the requirements of §192.636(b).**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-130.*

# SUBPART M
# MAINTENANCE

## §192.701
## Scope.

*[Effective Date: 11/12/70]*

**This subpart prescribes minimum requirements for maintenance of pipeline facilities.**

### GUIDE MATERIAL

Type B gathering lines are exempt from this subpart, except for §§192.703(c), 192.706, and 192.707.

For Type B gathering lines that are replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with the requirements for transmission lines (§192.9(d)).

## §192.703
## General.

*[Effective Date: 11/12/70]*

**(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.**

### GUIDE MATERIAL

**1 GENERAL**

Any time a pipeline is found to be damaged or deteriorated to the extent that its serviceability is impaired or leakage constituting a hazard is evident, immediate temporary measures should be employed to protect the public and property. If it is not feasible to make a permanent repair at the time of discovery, permanent repairs should be made as soon as feasible.

**2 REPAIR OF PIPE**

*2.1 General.*
Prior to repairing a pipeline, the operator should consider the operating conditions, design, and maintenance history, as necessary, to ensure that repair actions do not further damage the pipe. Where warranted, the operating pressure should be lowered, pipe exposure should be limited, access to the area should be limited, personnel protection should be provided, and fire extinguishing equipment should be available.

*2.2 Repairs to distribution lines.*

Methods of permanent repair to non-thermoplastic distribution lines include the following.

(a) Cutting out as a cylinder and replacing the piece of damaged pipe.
(b) Applying a full-encirclement welded split sleeve of appropriate design.
(c) Applying a properly designed bolt-on type of leak clamp or sleeve.
(d) For steel pipe, applying a fillet-welded steel plate patch of similar material of equal or greater thickness, of appropriate grade, and with rounded corners.

2.3 *Repairs to transmission lines and Type A gathering lines*.

For repairs to steel transmission lines and Type A gathering lines, see §§192.711, 192.713, 192.715, 192.717, and 192.751. Section 192.485 allows the alternative of lowering the MAOP on corroded transmission pipe where a safe operating pressure can be calculated based on the remaining strength of the corroded pipe. See guide material under §192.485.

2.4 *Permanent repairs to thermoplastic piping.*

Repair methods for thermoplastic piping include the following.

(a) Cutting out as a cylinder and replacing the piece of damaged pipe.
(b) Applying a properly designed bolt-on type saddle, leak clamp, or sleeve.
(c) Installing a repair sleeve meeting the requirements of ASTM D2513 (see §192.7).
(d) See guide material under §192.311.
(e) For gas flow control during repair (e.g., squeeze-off and re-opening), see 5 of the guide material under §192.321.

2.5 *Repair procedures.*

The repair should be made in accordance with a qualified repair procedure.

2.6 *Compression couplings in pipelines.*

Repairs using compression couplings and repairs to pipelines that may contain compression couplings should consider the following.

(a) Coupled pipe is subject to pullout near bends, near the end of the pipeline, at temporary end closures, while performing stoppering or stopping procedures, when the pipeline is severed, and while long sections of pipeline are exposed.
(b) Some factors that can contribute to pullout potential are the pipe diameter, material, and surface; operating pressure; temperature changes; buoyancy; and soil moisture, compaction, and type.
(c) The procedure for safely repairing the pipeline should include consideration of the following precautionary, preventive, and mitigating actions.
    (1) Reviewing maps and records to determine if couplings exist.
    (2) Reviewing and following manufacturer's recommendation for installing and maintaining compression couplings.
    (3) Analyzing each project for the potential of coupling pullout, including pullouts on adjacent line sections.
    (4) Performing an electrical continuity test to check for indications of unknown insulating couplings.
    (5) Reviewing contingency procedures to be used in the event of a pullout.
    (6) Reducing pressure prior to excavation.
    (7) Installing anchors sufficient to resist anticipated pullout forces caused by movement of the pipeline in any direction.
    (8) Reinforcing known couplings.
    (9) Minimizing the length of exposed pipe during the repair work.
    (10) Backfilling offset replacement piping before severing the pipeline.
    (11) Providing a separate excavation for pressure control operations to prevent injury from pullout of an unknown coupling.
    (12) Designing and installing protective sleeves or bridging when making mechanical joints that either connect plastic piping or plastic piping to steel piping. This is especially true for PE pipe manufactured prior to 1982, since some is known to be susceptible to premature brittle-like failures. Also, attention should be given to any recommendations by the pipe manufacturer. For

protective sleeves, see guide material under §192.367.

*2.7 Inspection and testing.*

(a) All repairs to distribution lines should be visually inspected and leak tested at operating pressure.
(b) All repairs to transmission lines should be tested in accordance with §192.719.
(c) For safety during pressurization, the operator should consider restricting access to pipeline facilities such as the following.
 (1) Test header.
 (2) Exposed piping and appurtenances.
 (3) Repair fittings.
 (4) Compression couplings.
 (5) Dead ends.
 (6) Areas near the pipeline facility that might be affected.

**3 CONSIDERATIONS FOR REPLACEMENT OR RENEWAL**

*3.1 All pipelines.*

A guide to assist an operator in developing a method of evaluating the serviceability and need for replacement or renewal of existing pipelines is AGA XL0702, "Distribution Pipe: Repair and Replacement Decision Manual."

*3.2 Cast iron pipe.*

See Guide Material Appendix G-192-18.

*3.3 Other considerations.*

A gas facility might be considered for replacement if located near an exposed, deteriorated electrical conduit.

**4 REALIGNMENT OF PIPING**

*4.1 Steel.*

(a) General.
Prior to realigning (moving in any direction) piping, the operator should establish a procedure for determining the feasibility of safely realigning the piping and performing the work. A reference for developing such a procedure is PRCI L51717, "Pipeline In-Service Relocation Engineering Manual."
 (1) *Feasibility analysis*. The procedure for determining the feasibility of safely realigning the pipe should include consideration of the following.
  (i) Determining the amount of realignment required.
  (ii) Reviewing the operating history of the involved section, such as records of leaks, damage, and external and internal corrosion.
  (iii) Reviewing the material properties of the pipe and associated valves and fittings, such as specification, rating or grade, wall thickness, SMYS, toughness, and seam and joint characteristics.
  (iv) Performing a new stress analysis, reviewing relevant prior stress analyses and safe practices established by prior projects.
  (v) Determining the maximum safe operating pressure during the realignment.
  (vi) When the feasibility analysis indicates a potentially unsafe condition may be caused by moving the pipe under normal operating conditions, consideration should be given to isolating the line segment, lowering the pressure in the segment, depressuring the segment, or other appropriate action.
 (2) *Performance of the work*. The procedure for performing the work should include consideration of the following.
  (i) Training and qualification of personnel for the realignment procedure.
  (ii) Monitoring the pressure during the realignment to ensure that the maximum safe operating

pressure is not exceeded.

(iii) Providing for shutdown and purging of the piping if necessary.
(iv) Minimizing employee and public exposure at the work site.
(v) Potential adverse effects of weather conditions, ground and surface water, and bank stability.
(vi) External inspection of the exposed pipe for variation from the feasibility study and for visible defects, such as dents, gouges, grooves, arc burns, corrosion, and coating damage.
(vii) Making appropriate repairs.
(viii) Full control by the operator of the actual realignment process.
(ix) The adequacy of pipe supports to prevent unintended movement.
(x) Ditch padding and backfill materials to prevent damage to the pipe and coating.
(xi) Backfill and compaction procedures to prevent additional movement due to settlement after realignment.

(b) Additional considerations for compression-coupled piping.
(1) *Feasibility analysis.* The procedure for determining the feasibility of safely realigning the piping should also include consideration of the following.
(i) Reviewing the manufacturers' recommendations for installing and maintaining compression couplings.
(ii) Analyzing each project for the potential of coupling pullout, including pullouts on line sections connected to each side of the project piping.
(iii) Installing anchors to resist unbalanced forces on each side of the project piping.
(iv) Reinforcing all involved couplings prior to actually realigning the pipe.
(2) *Performance of the work*. The procedure for performing the work should also include consideration of the following.
(i) Reducing pressure prior to excavating, reinforcing, and realigning.
(ii) Minimizing excavation during the locating and reinforcing activities.

(c) References.
(1) PRCI L51717, "Pipeline In-Service Relocation Engineering Manual," (PR218-9308).
(2) API RP 1117, "Movement of In-Service Pipelines."

*4.2 Cast iron*.

Realignment of cast iron pipe is not recommended. See Guide Material Appendix G-192-18.

*4.3 Plastic.*

Realignment of plastic pipe is not recommended except where replacement is not feasible. If realignment is necessary, then the following should be considered.

(a) General.
See 4.1 (a) and (b) above.

(b) Additional considerations.
(1) Damaged sections should be replaced.
(2) Recommendations of pipe and fitting manufacturers should be reviewed in determining the allowable pipe movement and joint deflection.
(3) To minimize or avoid stress concentration at joints during and after realignment, the operator should:
(i) Consider the effect of thermal stresses.
(ii) Provide continuous pipe support (e.g., bridging, protective sleeves, ditch grading, and proper backfill) to prevent movement from settlement after realignment. For protective sleeves, see guide material under §192.367.
(iii) Review records to determine the type of plastic material used in manufacturing the pipe. Thermosetting plastics (e.g., fiberglass reinforced epoxy composite pipe) and some thermoplastics (e.g., ABS and PVC) allow only marginal flexing of joints without damage.
(iv) During PE piping relocation, minimum bend radius recommendations should be observed to avoid overstressing joints at fittings in PE piping, which can lead to premature failures. For bend radius recommendations, see guide material under §192.367.

(v) Review records to determine the types of fittings that may be involved. Some fittings provide little, if any, pullout resistance.

(4) Branch lines and service lines connected to the section to be realigned should be reviewed and replaced or extended as necessary. Extensions will usually be required to prevent imposed tensile stresses in the pipe material due to the realignment.

(5) Buried valves should be properly supported and aligned for correct operational orientation.

## 5 GAS LEAKAGE CONTROL GUIDELINES

Guide Material Appendix G-192-11 (Natural Gas Systems) and Guide Material Appendix G-192-11A (Petroleum Gas Systems) provide guidelines for the detection, classification, and control of gas leakage. These appendices include information related to the prompt repair of hazardous leaks.

Type B operators must repair hazardous leaks as required by §192.9(d)(8) and may follow the guidelines of Table 3a Leak Classification and Action Criteria for Grade 1 leaks or other operator criteria to define hazardous leaks. Repairs to Type B gathering lines should be made in accordance with requirements for transmission lines.

# §192.705

## Transmission lines: Patrolling.

*[Effective Date: 07/08/96]*

**(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 20279, May 9, 1975; Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996]**

## GUIDE MATERIAL

## 1 GENERAL

Transmission lines and Type A gathering lines should be patrolled, as necessary, to observe factors affecting safe operation and to enable correction of potentially hazardous conditions. In addition to visual evidence of leakage, patrol considerations should include observation and reporting of potential hazards and conditions such as the following.

(a) Excavation, grading, demolition, or other construction activity that could result in the following.
  (1) Damage to the pipe.
  (2) Loss of support due to settlement or shifting of soil around the pipe.
  (3) Undermining or damage to pipe supports.
  (4) Loss of cover.
  (5) Excessive fill.
(b) Evidence that excavation, grading, demolition, or other construction activity may take place or has taken place, such as power equipment staged in the vicinity of transmission facilities or a freshly backfilled excavation over or near transmission facilities.
(c) Physical deterioration of exposed piping, pipeline spans, and structural pipeline supports, such as bridges, piling, headwalls, casings, and foundations.
(d) Land subsidence, earth slippage, soil erosion, extensive tree root growth, flooding, climatic conditions, and other natural causes that can result in impressed secondary loads.
(e) Need for additional transmission pipeline identification and marking in private rights-of-way and in rural areas.
(f) Damage to casing vents and leakage from encased pipe.
(g) Areas of continual earth-moving activities, such as quarries and industrial plants, which may require special attention.
(h) Indications along a pipeline route that may trigger the need for the operator to conduct a class location study under §192.609. Examples of such indications include the following.
  (1) Changes in the number of buildings intended for human occupancy.
  (2) New buildings, or changes in use for existing buildings.
  (3) Changes in land use.
    (i) Playgrounds.
    (ii) Camps and campgrounds.
    (iii) Recreational areas.

## 2 SCHEDULING

*2.1 General.*

Patrolling may be accomplished in conjunction with leak surveys, scheduled inspections, and other routine activities.

*2.2 Potentially hazardous locations.*

Locations or areas that are considered potentially hazardous may be patrolled more frequently based on the probable severity, timing, and duration of the hazard.

## 3 METHOD

Where practical, the patrol map or other documents (e.g., aerial photographs) used by the person making the patrol should identify areas near the transmission line that may require special attention. These areas may include locations where earthmoving activities are regularly performed, or where there are indications such as those listed under 1(h) above.

Consider using a method for the patrol person to compare current conditions with conditions observed during previous patrols.

**4 REPORTS**

Patrol reports should indicate hazardous conditions observed, corrective action taken or recommended, and the nature and location of any deficiencies. These reports should also include information about population density near the right-of-way, including indications such as those listed under 1(h) above.

**5 FOLLOW-UP**

In those areas where excavation equipment is used on an on-going basis, such as quarries and some industrial plants, consideration should be given to providing those excavators more frequent damage prevention and public education notification. See guide material under §§192.614 and 192.616.

## §192.706

### Transmission lines: Leakage surveys.

*[Effective Date: 02/11/95]*

**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.**

**[Issued by Amdt. 192-21, 40 FR 20279, May 9, 1975; Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994]**

**GUIDE MATERIAL**

The minimum frequency for leakage surveys of transmission lines and gathering lines is established by §192.706. See 4 and Table 192.935i of the guide material under §192.935 for transmission pipelines operating below 30% of SMYS located in Class 3 or Class 4 location, but not in a high consequence area. See 1.3, 1.4, and 1.5 of the guide material under §192.723 and the applicable sections of Guide Material Appendix G-192-11.

Leakage surveys of Type B gathering lines require the use of leakage detection equipment (§192.9(d)(8)).

## §192.707

### Line markers for mains and transmission lines.

*[Effective Date: 07/13/98]*

**(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 1/4 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 13502, Mar. 27, 1975 with Amdt. 192-20A, 41 FR 56807, Dec. 30, 1976; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976 with Amdt. 192-27 Correction, 41 FR 39752, Sept. 16, 1976; Amdt. 192-40, 47 FR 13818, Apr. 1, 1982; Amdt. 192-44, 48 FR 25206, June 6, 1983; Amdt. 192-73, 60 FR 14646, Mar. 20, 1995; Amdt. 192-85, 63 FR 37500, July 13, 1998]**

## GUIDE MATERIAL

### 1. GENERAL

(a) If an existing pipeline has undergone a conversion, its pipeline markers should be updated to accurately list natural gas as the product being transported.

(b) See Guide Material Appendix G-192-13, Section 3.

## §192.709

## Transmission lines: Record keeping.

*[Effective Date: 07/08/96]*

**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 a least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.**

**[Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996]**

## GUIDE MATERIAL

See Guide Material Appendix G-192-17 for the explicit requirements of each patrol, survey, inspection, or test required by Subparts L and M. Also, see guide material under §192.947 for records required under Subparts I, L, and M to be used as part of the operator's Integrity Management Program for transmission lines.

## §192.710

### Transmission lines: Assessments outside of high consequence areas.

*[Effective Date: 07/01/2020]*

**(a) *Applicability*: This section applies to onshore steel transmission pipeline segments with a maximum allowable operating pressure of greater than or equal to 30% of the specified minimum yield strength and are located in:**

**(1) A Class 3 or Class 4 location; or**

**(2) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (*i.e.*, "smart pig").**

**(3) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.**

**(b) *General*. (1) *Initial assessment.* An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of § 192.710(a) (*e.g.*, due to a change in class location or the area becomes a moderate consequence area), whichever is later.**

**(2) *Periodic reassessment.* An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.**

**(3) *Prior assessment.* An operator may use a prior assessment conducted before July 1, 2020 as an initial assessment for the pipeline segment, if the assessment met the subpart O requirements of part 192 for in-line inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(2) of this section calculated from the date of the prior assessment.**

**(4) *MAOP verification.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) for establishing MAOP may be used as an initial assessment or reassessment under this section.**

**(c) *Assessment method.* The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods:**

**(1) *Internal inspection.* Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible, such as corrosion, deformation and mechanical damage (*e.g.*, dents, gouges and grooves), material cracking and crack-like defects (*e.g.*, stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;**

**(2) *Pressure test.* Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;**

**(3) *Spike hydrostatic pressure test.* A spike hydrostatic pressure test conducted in accordance with § 192.506. A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and**

**related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;**

**(4) *Direct examination.* Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);**

**(5) *Guided Wave Ultrasonic Testing.* Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;**

**(6) *Direct assessment.* Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or**

**(7) *Other technology.* Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.**

**(d) *Data analysis*. An operator must analyze and account for the data obtained from an assessment performed under paragraph (c) of this section to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (*e.g.*, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.**

**(e) *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. 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 180 days is impracticable.**

**(f) *Remediation*. An operator must comply with the requirements in §§ 192.485, 192.711, and 192.713, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.**

**(g) *Analysis of information*. An operator must analyze and account for all available relevant information about a pipeline in complying with the requirements in paragraphs (a) through (f) of this section.**

**[Amdt. 192-125, Oct. 01, 2019]**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-125*

# §192.711

## Transmission lines: General requirements for repair procedures.

*[Effective Date: 10/01/10]*

**(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. 192-27B, 45 FR 3272, Jan. 17, 1980; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010]**

### GUIDE MATERIAL

(a) Prior to permanent mechanical or welded repair of a steel pipeline operating at greater than 20% SMYS, the operator should determine the thickness and integrity of the pipe wall by ultrasonic or other means. Where deterioration or lamination is found, steps should be taken to ensure a safe repair.

(b) See guide material under §§192.703, 192.713, 192.751, and 192.933.

# §192.712

## Analysis of predicted failure pressure.

*[Effective Date: 07/01/20]*

**(a) *Applicability*. Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.**

**(b) *Corrosion metal loss*. When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R-STRENG (incorporated by reference, *see* § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.**

**(c) [Reserved]**

**(d) *Cracks and crack-like defects*.**

**(1) *Crack analysis models*. When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).**

**(2) *Analysis for crack growth and remaining life.* If the pipeline segment is**

**susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.**

**(i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph (e)(2) of this section must be used.**

**(ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).**

**(iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.**

**(3) *Cracks that survive pressure testing*. For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph (d)(1) of this section. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v- notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:**

**(i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;**

**(ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in § 192.607;**

**(iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or**

**(iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.**

**(e) *Data.* In performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows.**

**(1) An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements.**

**(2) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator shall use conservative assumptions as follows:**

**(i) *Material toughness*. An operator must use one of the following for material toughness:**

**(A) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;**

**(B) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607;**

**(C) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;**

**(D) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or**

**(E) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with § 192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.**

**(ii) *Material Strength.* An operator must assume one of the following for material strength:**

**(A) Grade A pipe (30,000 psi), or**

**(B) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.**

**(iii) Pipe dimensions and other data. Until pipe wall thickness, diameter, or other data are determined and documented in accordance with § 192.607, the operator must use values upon which the current MAOP is based.**

**(f) *Review.* Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.**

**(g) *Records.* An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:**

**(1) The technical approach used for the analysis;**
**(2) All data used and analyzed;**
**(3) Pipe and weld properties;**
**(4) Procedures used;**
**(5) Evaluation methodology used;**
**(6) Models used;**
**(7) Direct in situ examination data;**
**(8) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;**
**(9) Pressure test data and results;**
**(10) In-the-ditch assessments;**
**(11) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;**
**(12) All finite element analysis results;**
**(13) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;**
**(14) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;**
**(15) Safety factors used for fatigue life and/or predicted failure pressure calculations;**
**(16) Reassessment time interval and safety factors;**
**(17) The date of the review;**
**(18) Confirmation of the results by qualified technical subject matter experts; and**
**(19) Approval by responsible operator management personnel.**

**[Amdt. 192-125, Oct. 01, 2019]**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-125.*

# §192.713

## Transmission lines: Permanent field repair of imperfections and damages.

*[Effective Date: 01/13/00]*

**(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. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999]**

**GUIDE MATERIAL**

## 1 GENERAL

*1.1 Repair method.*

There are a number of repair methods available to restore the serviceability of transmission pipelines. However, operators are cautioned that not all repair methods are suitable for permanent repair of leaking or through-wall defects. For leak repair, see §192.717. When evaluating the types of repair, the operator should consider factors such as the following.

(a) Type of defect: Corrosion, dents, gouges, stress concentrators, unacceptable wrinkle bends, cracks, crack-like defects, compound defects *(e.g.,* dents with corrosion or stress concentrators), defects in the pipe wall.
(b) Status of defect: Leaking or non-leaking.
(c) Class location or HCA area.
(d) Location of defect on the pipe such as clock position or along a seam or girth weld.
(e) Pipe properties including diameter, thickness, grade, seam type.
(f) MAOP and operating stress levels (% SMYS) of the pipeline.
(g) Remaining strengths calculations (see guide material under §192.485).
(h) Required pressure reduction or other operational issues (see 2 below).
(i) Temporary or permanent repair.
(j) Availability of repair materials.

*1.2 Repair method selection.*

The repair method selected should:

(a) Have or result in a restored strength at least equal to that required for the MAOP of the pipe being replaced; and
(b) Be capable of withstanding the anticipated circumferential and longitudinal stresses, including additional stress due to external loading.

*1.3 Impairment beyond area of concern.*

The operator should consider the possibility that some degree of impairment might have occurred beyond the area of immediate concern. (For information regarding corrosion, see guide material under §192.459). The impairment might be due to a defect in the seam weld, external or internal corrosion, or damage by outside forces or excavation. The pipe on each side of the known impairment should be examined to determine the extent of the repair.

*1.4 Written procedures.*
The operator should have written procedures for each type of repair and should consider developing site-specific written procedures as needed to address the specific conditions.

*1.5 Other*
Other items the operator should consider include the following.

(a) Trench and excavation safety (see 2.8 of the guide material under §192.605).
(b) Potential for accidental ignition (see guide material under §192.751).
(c) Blowdown and purging plans (see Guide Material Appendix G-192-12).
(d) Qualification of personnel performing repairs (see guide material under §192.805).
(e) Ability to use internal inspection devices (see §192.150).
(f) PRCI Pipeline Repair Manual (PR-218-9307).

## 2 REPAIR PRESSURE (§192.713(b))

*2.1 General*.

(a) In establishing a safe level of pressure in a pipeline that is to remain in service during repair operations, the primary consideration is the severity of the defect to be repaired. This includes consideration of both depth and geometry (*i.e.,* the amount of stress concentration, such as in sharp-bottomed gouges). Severe defects should not be repaired under pressure unless the operator has sufficient experience to make a sound evaluation of the defect. In addition, the effect of any known secondary stresses should be considered.
(b) The operator should also consider the effect of pressure reductions on firm-service requirements, service interruptions, or other operational requirements. If the operator has a control room, communication is critical during the repair process (see 3.3 and 3.4 of the guide material under §192.631).
(c) A common practice is to reduce the operating pressure to a level not exceeding 80% (for composite wrap repairs, see 7 below) of the pressure at the time the condition was discovered until the repair is completed.

*2.2 Special consideration*.
While welding reinforcements directly to pressurized pipe has been done successfully at higher stress levels, the following formula describes a recommended maximum pressure for this repair procedure.

$$P = \frac{2S(t - {}^{3}\!/_{32})(0.72)}{D}$$

Where:

| | | |
|---|---|---|
| $P$ | = | Internal pressure, psig |
| $S$ | = | Specified minimum yield strength, psi |
| $t$ | = | Nominal pipe wall thickness, inches |
| $D$ | = | Nominal outside diameter, inches |

*2.3 Manufacturer's recommendations*
The operator is advised to follow manufacturer's recommendations regarding pressure reductions for repair methods such as composite wrap repairs.

## 3 WELDING

*3.1 Welding*.

(a) Appropriate procedures for welding on pipelines in service should be used. Some important factors to be considered in these procedures are the use of a low-hydrogen welding process, the welding sequence, the effect of wall thickness and heat input, and the quenching effect of the gas flow.
(b) Welding should be done only on sound metal far enough from the defect so that the localized heating will not have an adverse effect on the defect. The soundness of the metal may be determined by

visual and other nondestructive inspection.

(c) A reference is API Std 1104, "Welding of Pipelines and Related Facilities", Appendix B, "In-Service Welding" (see §192.7).

*3.2 Additional precautions*.

(a) Care should be taken in excavating around the pipe so that it is not damaged.

(b) Pounding on the pipe (e.g., to remove corrosion products or pipe coating, or to improve the fit of the sleeve) should be avoided.

*3.3 Reliable engineering tests and analyses.*

See guide material under §192.485.

## 4 PIPE REPLACEMENT (§192.713(a)(1))

Pipe replacement by cutting out and replacing a cylinder of pipe is a repair option under §192.713 and should be considered for repair of dents, wrinkles, or other pipe changes such as expanded pipe or buckles. Replacement can use pipe that has been pre-tested to the appropriate pressure for the MAOP.

## 5 SPLIT SLEEVE REPAIR (§192.713(a)(2))

*5.1 General.*

(a) The use of an appropriately designed full-encirclement split sleeve is recognized as an acceptable repair method. Other methods are also available, such as the use of composite-reinforced wrap material addressed in 7 below. The operator is advised to follow manufacturer's instructions for installation.

(b) The operator should determine the type of sleeve to be used in the repair.

(1) Type A sleeve provides defect reinforcement.

This type of split sleeve restores the strength of the pipe by containing and reinforcing the defect and reduces bulging of a defective area. The two parts of the split sleeve are installed around the pipe to provide the required reinforcement. Effectiveness of the repair is improved by using a filler material (e.g., polyester epoxy) in the defect which provides support. Type A sleeves are assembled by bolting or welding (welding to the carrier pipe might not be necessary). This type of sleeve cannot be used to repair leaks and should not be used for circumferential defects or deep defects since corrosion could occur in the annular space between the carrier pipe and sleeve.

*Note*: Composite wrap repairs are a type of reinforcing sleeve (see 7 below).

(2) Type B sleeve is a pressure containing sleeve.

A pressure containing split sleeve provides a different function and can be used to contain a leak or to reinforce an area where a defect exists. Because the sleeve contains pressure, operators are advised to select a sleeve commensurate with the current carrier pipe MAOP. The application of the Type B sleeve requires the sleeve ends to be fillet welded to the pipe. The use of low hydrogen welding procedures, additional support of the pipe because of the additional weight, and welding inspection of the fillet welds should be considered before using this type of repair.

*Note*: Some Type B sleeves might also be called by other names (e.g., pumpkins, watermelons, turtles) due to the shape of the sleeves being suitable to fit around couplings.

(c) In determining the length of the repair, the operator should consider that:

(1) Some degree of impairment might have occurred beyond the area of immediate concern (see 1.3 above), and

(2) Full-encirclement sleeves should not be less than 4 inches in length.

(d) A wide variety of repair methods have been used successfully in the natural gas pipeline industry. Sleeves may be used to reduce the stress in, or reinforce, a pipe defect that is not leaking, or to repair a leaking defect. It is important that any repair method or sleeve be designed and tested to ensure its reliability for the conditions of installation.

*5.2 Fillet welds.*

Fillet welds on pressurized carrier piping are prone to cracking due to the extreme cooling action.

Because examination of completed welds by radiographic or ultrasonic means might not detect such cracking due to the geometry of the fillet weld. Use of the following is recommended.

(a) Low-hydrogen welding process
(b) Multi-pass welding techniques with visual examination after each pass
(c) Magnetic particle or liquid penetrant inspection if visual examination indicates further nondestructive inspection is necessary.

*5.3 Design considerations for repair sleeves.*

A reference for one set of sleeve designs is PRCI L22279, "Further Studies of Two Methods for Repairing Defects in Line Pipe."

For evaluating other available designs or developing new designs, consider the following factors.

(a) Sleeves should be designed for strength at least equal to the maximum allowable operating pressure of the repaired pipe.
(b) Sleeves should not be less than 4 inches in length. In determining the length of a sleeve, the operator should consider that some degree of impairment might have occurred beyond the immediate area. See 1.3 above.
(c) The use of a low-hydrogen welding procedure for longitudinal and circumferential welds. The integrity of these welds is affected by heat dissipation due to gas flow through the line and extra metal mass adjacent to the weld.
(d) Circumferential welds at the sleeve ends are required when repairing a leaking defect. However, end welds may or may not be beneficial for a non-leaking defect. If end welds are used on a non-leaking defect, consideration should be given to equalizing the pressure across the defect. One way to do this is by tapping the carrier pipe in order to connect the annular space between the carrier pipe and the sleeve to the pressure inside the carrier pipe.
(e) Sealing the ends of non-pressure containing sleeves, possibly by means other than welding, to prevent corrosion in the annular space between the carrier pipe and the sleeve.
(f) The capacity of end welds to withstand anticipated circumferential and longitudinal stresses, including external forces. Special attention should be given to stresses resulting from unusually long sleeves or sleeves subject to bending stresses.

**6 GRINDING OR BUFFING**

(a) Grinding or buffing is a suitable method of removing the following.
  (1) Surface dents or gouges with sharp edges or other stress concentrators. A gouge is defined as pipe material moved, but not necessarily metal removed from the pipe wall.
  (2) Other localized surface defects such as arc burns.
(b) The operator should develop a site-specific written plan for each grinding repair. The plan should include the following information.
  (1) Pipe information such as pipe grade and wall thickness.
  (2) Maximum amount of pipe wall thickness that can be removed if the grinding is the sole repair method, which is calculated using the design formula in §192.107 or remaining strength calculations.
(c) After grinding, the area should be checked with nondestructive testing such as magnetic particle or dye penetration technology to determine if there are any remaining cracks or other stress concentrations.
(d) Grinding or buffing should continue until all cracks or stress concentrators are removed or until maximum specified removal or wall thickness is reached. In no instance should more than 40% of the wall thickness be removed during a grinding or buffing repair. The grinding or buffing should leave smooth contours with no sharp edges. If maximum metal removal is reached before all cracks are removed, the operator should consider another method of repair or modify the plan to include some sort of strength reinforcement such as a composite wrap repair.
(e) In-service grinding repairs must be done by qualified personnel (see Subpart N).
(f) The final wall thickness should be recorded since pipe wall removal could affect future class location changes or integrity management repairs.

## 7 COMPOSITE WRAP REPAIRS

(a) A composite wrap is a type of repair designed to restore the strength to corroded or damaged pipe. Some manufacturers provide for custom repairs based on actual conditions; others use a set number of wraps for all types of damage. Review the manufacturer's installation requirements before deciding to use a composite wrap to make a permanent repair.

(b) Composite wrap repairs generally consist of a mastic or epoxy binder and a compatible wrapping material that is installed over the binder. The epoxy or mastic is used to fill in the pipe defects to support the wraps installed above. The multiple layers of wrapping material are "glued" together and to the pipe. After a specified curing time, the wrap restores strength to the pipe.

(c) The operator should review the manufacturer's guidelines to determine if the materials can be used to repair certain defects. Generally, composite wrap repairs cannot be used for repairs of leaks or cracks, or seam defects in ERW pipe. Composite wrap repairs are good for corrosion defects, dents, gouges (if stress concentrators are removed), non-ERW seam defects, and girth weld defects. They may also be used to reinforce grinding repairs where too much pipe wall has been removed.

(d) Multiple wraps can be placed end to end for longer repairs.

(e) Manufacturer's instructions for the composite wrap are to be followed when:

(1) Installing composite wrap repairs.

(2) Extending the repair beyond each end of the defect.

(3) Training personnel to perform the repairs.

(4) Reducing pressure during the repair and curing time (many require a significant pressure reduction up to approximately 50%).

(f) Because composite wrap repairs are not metallic, an operator should consider the use of a magnetic marker such as a steel band or small steel coupon on or near the repair to indicate on MFL ILI tools that a repair has been made.

## 8 HOT TAPS

A hot tapping operation is an in-service repair option that may be used to remove small in-wall defects found in steel pipe. In general, fittings that are normally used for tapping are welded onto the pipeline and tapped, removing the pipe defect in the tap coupon. The hot tap fitting reinforces the tapped hole in the pipeline. Items to consider include the following.

(a) The location of the defect should be in a place that makes using a hot tap fitting practical and in accordance with the fitting manufacturer's installation recommendations (*e.g.,* the fitting should be horizontal or vertical, the installation machine should be accessible and operable).

(b) The removed pipe coupon should completely remove the defect.

(c) The location should not invite potential damage to the hot tap fitting at a future time.

(d) The availability of properly-sized hot tap fittings in the needed time frame for the repair.

(e) Less costly repair options might be available.

## 9 DIRECT DEPOSITION WELDING

(a) Direct deposition welding may be used for repair of non-leaking defects caused by corrosion (internal or external) and to smooth ground-out areas without a dent. Additional metal is deposited in the anomaly using welding techniques. In the case of internal corrosion, the wall build-up is on the exterior of the pipe. Legacy long seams should not be repaired with direct deposition welding. Integrity concerns for direct deposition welding repairs include the following.

(1) Risk of burn-through during the repair.

(2) Possible cracks or other defects in the deposited weld material.

(3) Fatigue cracks or hydrogen embrittlement cracking.

(4) Insufficient repair strength due to an inadequate deposition of material.

(b) The operator must develop a welding procedure specific for the repair (see §192.225) and should consider the following.

(1) Visible signs of corrosion should be removed using a wire brush or by sanding.
(2) Low hydrogen electrodes should be used for all passes of the weld deposition.
(3) The number of passes needed to attain the required metal deposition should be defined.
(4) The deposited weld material should completely fill the corrosion pit or defect to ensure pipe wall integrity.
(5) The repair should be ground flush for inspection purposes and should be non-destructively tested to ensure the integrity of the repair.

**10 RECORD KEEPING**

Records showing the date, location, and description of the repair must be retained for the life of the pipeline (§192.709(a)). The description of the repair and related information should include the following.
(a) Data which supports the MAOP of the line such as materials and testing information, including pressure charts.
(b) Personnel qualification.
(c) Site-specific procedures (as for grinding or direct deposition welding),
(d) Other information as determined by the operator.

## §192.715

### Transmission lines: Permanent field repair of welds.

*[Effective Date: 07/13/98]*

**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 1/8 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.**

**[Amdt. 192-85, 63 FR 37500, July 13, 1998]**

**GUIDE MATERIAL**

See guide material under §192.713.

## §192.717

### Transmission lines: Permanent field repair of leaks.

*[Effective Date: 01/13/00]*

**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 p.s.i. (276 MPa) gage 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. 192-11, 37 FR 21816, Oct. 14, 1972; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999]**

### GUIDE MATERIAL

(a) For information regarding replacement and repairs, see guide material under §192.713.

(b) For information regarding reliable engineering tests and analyses, see guide material under §192.485.

(c) For information regarding scheduling integrity management repairs, see 2 of the guide material under §192.933.

## §192.719

## Transmission lines: Testing of repairs.

*[Effective Date: 12/18/86]*

**(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.**

**[Amdt. 192-54, 51 FR 41634, Nov. 18, 1986]**

### GUIDE MATERIAL

When tie-in girth welds are not strength tested, they should be nondestructively tested in accordance with §192.241.

## §192.720

## Distribution systems: Leak repair.

*[Effective Date: 01/22/19]*

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

**[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

**GUIDE MATERIAL**

*No guide material available at present.*

# §192.721
## Distribution systems: Patrolling.
*[Effective Date: 07/08/96]*

**(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 place 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.**

**[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996]**

**GUIDE MATERIAL**

### 1 GENERAL

Distribution mains should be patrolled, as necessary, to observe factors affecting safe operation and to enable correction of potentially hazardous conditions. In addition to visual evidence of leakage, patrol considerations should include observation and reporting of potential hazards such as the following.

(a) Excavation, grading, demolition or other construction activity which could result in the following.
   (1) Damage to the pipe.
   (2) Loss of support due to settlement or shifting of soil around the pipe.
   (3) Undermining or damage to pipe supports.
   (4) Loss of cover.
   (5) Excessive fill.

(b) Evidence that excavation, grading, demolition, or other construction activity may take place or has taken place, such as power equipment staged in the vicinity of distribution facilities or a freshly backfilled excavation over or near distribution facilities.

(c) Physical deterioration of exposed piping, pipeline spans, and structural pipeline supports, such as bridges, piling, headwalls, casings, and foundations.

(d) Land subsidence, earth slippage, soil erosion, extensive tree root growth, flooding, climatic conditions, and other natural causes that can result in impressed secondary loads.

(e) Need for additional distribution pipeline identification and marking in private right-of-way and in rural areas.

(f) Damage to casing vents and carrier pipe leakage at cased crossings.

### 2 SCHEDULING

*2.1 General*.

Patrolling may be accomplished in conjunction with leak surveys, scheduled inspections, and other routine activities.

*2.2 Potentially hazardous locations*.

Locations or areas that are considered potentially hazardous may be patrolled more frequently based on the probable severity, timing, and duration of the hazard.

## 3 SPECIAL LOCATIONS

Places or structures where physical movement or external loading may cause leakage or failure should be identified by the operator based on knowledge of the system characteristics and problem areas. Where a main or its support structure is constructed and maintained to resist movement and external loading, the operator may determine that special-location patrols are not required.

Areas where an operator should consider performing increased patrol activity include the following.

(a) Bridge crossings.
(b) Aerial crossings.
(c) Unstable river banks.
(d) Exposed water crossings.
(e) Areas susceptible to washout.
(f) Landslide areas.
(g) Areas susceptible to earth subsidence, such as mines and landfills.
(h) Tunnels.
(i) Railroad crossings.
(j) Attachments to buildings or other structures.
(k) Facilities or support structures that require maintenance, until repaired.

## 4 REPORTS

Patrol reports should indicate hazardous conditions observed, corrective action taken or recommended, and the nature and location of any deficiencies.

# §192.723

## Distribution systems: Leakage surveys.

*[Effective Date: 07/14/04]*

**(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.**

**[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-70, 58 FR 54524, Oct. 22, 1993; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69**

**FR 54591, Sept. 9, 2004]**

**GUIDE MATERIAL**

## 1 FREQUENCY

*1.1 Business districts*.

In determining business districts, the following should be considered.

(a) Areas where the public regularly congregates or where the majority of the buildings on either side of the street are regularly utilized for industrial, commercial, financial, educational, religious, health, or recreational purposes.
(b) Areas where gas and other underground facilities are congested under continuous street and sidewalk paving that extends to the building walls on one or both sides of the street.
(c) Any other area that, in the judgment of the operator, should be so designated.

*1.2 Minimum requirements*.

The minimum frequency for leakage surveys is established by §192.723(b).

*1.3 Increased frequency*.

Consideration should be given to increased frequency for leak surveys based on the particular circumstances and conditions. Surveys should be conducted most frequently in those areas with the greatest potential for leakage and where leakage could be expected to create a hazard. Factors to be considered in establishing the frequency of leak surveys include the following.

(a) Piping system. Age of pipe, materials, type of facilities, operating pressure, leak history records, and other studies.
(b) Corrosion. Known areas of significant corrosion, or areas where corrosive environments are known to exist. Cased crossings of roads, highways, railroads, etc., due to susceptibility to unique corrosive conditions.
(c) Piping location. Proximity to buildings or other structures and the type and use of the buildings. Proximity to areas of concentrations of people.
(d) Environmental conditions and construction activity. Conditions that could increase the potential for leakage or cause leaking gas to migrate to an area where it could create a hazard such as the following.
    (1) Weather conditions.
    (2) Areas of known frost heaving.
    (3) Wall to wall pavement.
    (4) Porous soil conditions.
    (5) Areas of high construction activity.
    (6) Trenchless excavation activities (e.g., boring).
    (7) Blasting. See Guide Material Appendix G-192-16.
    (8) Large earth moving equipment.
    (9) Heavy traffic.
    (10) Unstable soil or areas subject to earth movement.
(e) Other. Any other condition known to the operator that has significant potential to initiate a leak or to permit leaking gas to migrate to an area where it could result in a hazard, such as the following.
    (1) Earthquake.
    (2) Subsidence.
    (3) Flooding.
    (4) An increase in operating pressure.
    (5) The extensive growth of tree roots around pipeline facilities that can exert substantial longitudinal force on the pipe and nearby joints.

*1.4 Special one-time surveys*.

Special one-time surveys should be considered following exposure of the pipeline to unusual stresses (e.g., earthquakes, blasting) or trenchless installation of foreign buried facilities that cross gas pipelines.

*1.5 Establishment and review of survey frequency.*

Leak survey frequencies should be based on operating experience, sound judgment, and a knowledge of the system. Once established, frequencies should be reviewed periodically to affirm that they are still appropriate. Leak surveys may be accomplished in conjunction with patrolling, scheduled inspections, and other routine activities.

**2 GAS LEAKAGE CONTROL GUIDELINES**

See Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems.

## §192.725

### Test requirements for reinstating service lines.

*[Effective Date: 11/12/70]*

**(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.**

**GUIDE MATERIAL**

No guide material necessary.

## §192.727

### Abandonment or deactivation of facilities.

*[Effective Date: 02/17/09]*

**(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 20694, Oct. 3, 1972; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-89, 65 FR 54440, Sept. 8, 2000 with Amdt. 192-89 Correction, 65 FR 57861, Sept. 26, 2000; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; Amdt. 192-103, 72 FR 4655, Feb. 1, 2007; RIN 2137-AE29, 73 FR 16562, Mar. 28, 2008; RIN 2137-AE29 (#2), 74 FR 2889, Jan. 16, 2009]**

## GUIDE MATERIAL

*Note*: Although not required, operators of Type B gathering lines should consider the following when abandoning facilities.

## 1 GENERAL

(a) The following procedural guidance covers the maintenance of pipelines (including service lines) not actively being used to transport gas and the permanent abandonment of transmission lines, Type A gathering lines, distribution mains, and distribution service lines. See 5 below for information regarding inactive pipelines.

(b) For planned shutdown in connection with abandonment or deactivation, see Guide Material Appendix G-192-12.

## 2 ABANDONMENT OF TRANSMISSION PIPELINES AND DISTRIBUTION MAINS

*2.1 Check prior to abandonment*.

Office records should be checked and necessary field checks should be made to ensure the pipelines or mains scheduled for abandonment are disconnected from all sources and supplies of gas, such as other pipelines, mains, crossover piping, meter stations, customer piping, control lines, and other appurtenances.

*2.2 Residual gas or hydrocarbons.*
Abandonment should not be completed until it has been determined that the volume of natural gas or liquid hydrocarbons contained within the abandoned section poses no potential hazard. Generally, it is advisable to purge 8-inch and larger pipe and long segments of smaller diameter pipe.

*2.3 Purging*.
Pipelines or mains may be purged using air, inert gas, or water. If air is used as the purging agent, precautions should be taken to ensure that no liquid hydrocarbons are present. See §192.629 and AGA XK1801, "Purging Manual" for purging of natural gas and liquid hydrocarbons.

*2.4 Sealing*.
Acceptable methods of sealing pipeline or main openings include, as applicable, the following.
(a) Using normal end closures, such as welded or screwed caps, screwed plugs, blind flanges, and mechanical joint caps and plugs.
(b) Welding steel plate to pipe ends.
(c) Filling ends with a suitable plug material.
(d) Pinching the ends closed.

*2.5 Additional considerations in addition to purging and sealing*.
In addition to purging and sealing, consideration should be given to the following.
(a) Filling the abandoned segment with water or an inert gas to prevent potential combustion hazard.
(b) Other action designed to prevent hazardous cave-ins resulting from pipe collapse caused by corrosion or external loading.

*2.6 Segmenting the abandoned sections*.
All valves left in the abandoned segment should be closed. If the segment is long and there are few line valves, consideration should be given to plugging the segment at intervals.

*2.7 Removal of above-grade facilities and filling voids.*
All above-grade valves, risers, and vault and valve box covers should be removed. Vault and valve box voids should be filled with suitable compacted backfill material.

## 3 ABANDONMENT OF DISTRIBUTION SERVICE LINES IN CONJUNCTION WITH MAIN ABANDONMENT

*3.1 Curb valves and curb boxes*.
All curb valves should be closed. The top section of curb boxes located in dirt areas should be removed and the void filled with suitable compacted backfill material. If boxes are set in concrete or asphalt, they should be filled with suitable compacted backfill material to an appropriate distance from the top of the box and the fill completed with suitable paving material.

*3.2 Meter risers and headers*.
Meter risers and headers should be dismantled and removed from the premises.

*3.3 Service lines below grade through a basement wall*.
Where a service line enters below grade through a basement wall, the end of the service line should be plugged and a cap should be installed as close to the face of the wall as practical. It is not necessary to remove pipe from the wall unless required by particular circumstances.

*3.4 Outside meter set assembly and above-grade entrances*.
Service lines terminating at an outside meter set assembly or an above-grade entrance should be cut and capped at an appropriate depth below grade.

## 4 ABANDONMENT OF SERVICE LINES FROM ACTIVE MAINS

*4.1 Disconnecting*.
Service lines abandoned from active mains should be disconnected as close to the main as practical.

*4.2 Sealing*.
The end of the abandoned portion of the service line nearest the main should be plated, capped, plugged, pinched, or otherwise effectively sealed.

*4.3 Other actions*.
(a) The remainder of the service line should be abandoned as recommended in 3 above.
(b) The operator should consider the development of criteria to map or otherwise document service line stubs that are not disconnected within close proximity to the main.

## 5 INACTIVE PIPELINES

Pipelines not actively used to transport gas might be informally referred to as “idled,” “inactive,” or “decommissioned.” These shut-down and usually isolated pipelines might still contain gas at reduced pressures. For pipelines that have not been abandoned (permanently removed from service), operators must continue to comply with relevant safety requirements of Part 192 (e.g., periodic maintenance, integrity management assessments, damage prevention program, public awareness program). See Advisory Bulletin ADB-2016-05 (81 FR 54512, August 16, 2016; reference Guide Material Appendix G-192-1, Section 2) for additional guidance on operational status.

*5.1 General.*
Each operator should consider the following elements when determining whether to abandon or continue maintaining an inactive pipeline.
(a) Location (e.g., business district, urban, suburban, rural).
(b) Type of piping material.
(c) Joining method (e.g., welding, fusion, compression couplings).
(d) Cathodic protection.
(e) Operating pressure.
(f) Likelihood of reactivation.
(g) Leakage and maintenance history.
(h) Proposed construction.

*5.2 Continuing maintenance.*
Provisions for continuing maintenance of inactive pipelines should be included in the procedural manual for operations, maintenance, and emergencies required under §192.605. (See guide material under §192.3 for definition of "inactive pipeline.") Examples of such maintenance include the following.
(a) Regularly scheduled leak surveys and patrolling.
(b) Corrosion control monitoring of cathodically protected systems.
(c) Maps and records for damage prevention.
(d) Evaluating aboveground piping for the following.
  (i) Atmospheric corrosion.
  (ii) Susceptibility to damage from vehicles and other forces.
  (iii) Unauthorized activities.

## 6 INACTIVE SERVICE LINES

In addition to 5.2 above, the operator should consider the following for continuing maintenance of inactive service lines.

(a) Identifying and documenting the location of inactive service lines in a record management system.

(b) Developing criteria for abandonment.

## §192.729

**(Removed.)**

*[Effective Date: 02/11/95]*

## §192.731

**Compressor stations: Inspection and testing of relief devices.**

*[Effective Date: 11/22/82]*

**(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.**

**[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982]**

### GUIDE MATERIAL

The MAOP of regulated segments of gathering lines could be protected by equipment that is located in non-regulated compressor stations. While the compressor station might not be subject to Part 192 due to its location, individual devices that provide overpressure protection or isolation of downstream regulated segments could be regulated.

Although not required for non-regulated devices, operators of Type B gathering lines should consider performing routine inspections of overpressure protection devices.

## §192.733

**(Removed.)**

*[Effective Date: 02/11/95]*

## §192.735

**Compressor stations: Storage of combustible materials.**

*[Effective Date: 08/06/15]*

**(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).**

**[Amdt. 192-119, 80 FR 168, Jan. 5, 2015 with Amdt. 192-119 Correction, 80 FR 46847, Aug. 6, 2015]**

**GUIDE MATERIAL**

No guide material necessary.

## §192.736

## Compressor stations: Gas detection.

*[Effective Date: 07/13/98]*

**(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.**

**[Issued by Amdt. 192-69, 58 FR 48460, Sept. 16, 1993; Amdt. 192-85, 63 FR 37500, July 13, 1998]**

**GUIDE MATERIAL**

### 1 GENERAL

See §192.171 for design of gas detection and alarm systems.

### 2 MAINTENANCE AND TESTING OF GAS DETECTION AND ALARM SYSTEMS

The operator should develop the following.

(a) Maintenance and testing procedures to ensure proper function of the gas detectors and alarm system.

(b) Procedures for calibrating the gas detection equipment and verifying that the alarms are functioning properly.

## §192.737

### (Removed.)

*[Effective Date: 02/11/95]*

## §192.739

### Pressure limiting and regulating stations: Inspection and testing.

*[Effective Date: 10/08/04]*

**(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 pressures 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. |

**[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-96, 69 FR 27861, May 17, 2004 with Amdt. 192-96 DFR Confirmation, 69 FR 54248, Sept. 8, 2004]**

### GUIDE MATERIAL

### 1 GENERAL

*1.1 Gathering lines.*

(a) The MAOP of gathering lines could be protected by equipment that is located outside of the regulated segment of pipeline. While the pressure limiting station, relief device, or regulating station might not be subject to Part 192 due to its location, individual devices that provide overpressure protection or isolation of downstream regulated segments could be regulated by function.

(b) Although not required for non-regulated devices, operators of Type B gathering lines should consider performing routine inspections of overpressure protection devices.

*1.2 General considerations.*

(a) Prior to operating equipment, a review of the station's operating mode(s) should be performed using resources such as station schematics or SME input. The operator should follow system operation procedures including applicable recommendations for Control Room Management plans. See guide material under §192.631.

(b) Where necessary, consider marking or labeling the equipment requiring special attention such as regulator bypass valves, relief device isolation valves, and valves associated with control, sensing, and supply lines. See guide material under §192.203.
(c) When it is necessary to continue gas flow through a manually controlled bypass to inspect or test station components, the manual valve should be operated by personnel who are qualified (see Subpart N) to control the pressure in the downstream system at or below its MAOP. The pressures should be continuously monitored and the valve adjusted to prevent an overpressure condition. The
(d) manual bypass valve should be clearly marked showing the direction it is to be turned to either open or close the valve.

## 2 VISUAL INSPECTIONS

Visual inspections should be made to determine that a satisfactory condition exists which will allow proper operation of the equipment. The following should be included in the inspection, where necessary.
(a) Station piping supports, pits, and vaults for general condition and indications of ground settlement. Prior to entering a vault that has restricted openings (e.g., manholes) or which is more than four feet deep, and while working therein, tests should be made of the atmosphere in the vault. See guide material under §192.749 for atmospheric test procedures.
(b) Station doors and gates, and pit and vault covers to ensure that they are functioning properly and that access is adequate and free from obstructions.
(c) Ventilating equipment installed in station buildings or vaults for proper operation and for evidence of accumulation of water, ice, snow, or other obstructions.
(d) Control, sensing, and supply lines for conditions that could result in a failure.
(e) All locking devices for proper operation.
(f) Posted station schematics for correctness.

## 3 STOP VALVES

An inspection or test of stop valves should be made to ensure that the valves will operate and are correctly positioned. Caution should be used to avoid any undesirable effect on pressures during operational checks. The following should be included in the inspection or test.
(a) Station inlet, outlet and bypass valves.
(b) Relief device isolating valves.
(c) Control, sensing, and supply line valves.

## 4 PRESSURE REGULATORS

*4.1 General operating conditions*.
Consideration should be given to taking the station out of service during inspection and testing activities. Each pressure regulator used for pressure reduction or for pressure limiting should be inspected or tested. The procedure should ensure that each regulator is in good working order, controls at its set pressure, operates or strokes smoothly, and shuts off within the expected and accepted limits. If acceptable operation is not obtained during the operational check, the cause of the malfunction should be determined and the appropriate components should be adjusted, repaired, or replaced as required. After repair, the regulator should be checked for proper operation.

*4.2 Special conditions*.
(a) Regulator bodies that are subjected to erosive service conditions may require visual internal inspection.
(b) More frequent inspections or additional inspections may be required as a result of construction and hydrostatic testing upstream.
(c) More frequent inspections or additional inspections may be required as a result of abnormal changes in operating conditions or unusual flows or velocities.
(d) Whenever abnormal pressures are imposed on pressure or flow devices, the event should be

investigated and a determination made as to the need for inspection and repairs.

(e) Inspection and testing should be performed during times of low station throughput or when the station can be taken out of service, if practical.

## 5 RELIEF DEVICES

(a) The inspection or test should ensure the following.
 (1) Correct set pressure of relief devices. See 5(b) below for testing for correct set pressure.
 (2) Correct liquid level of liquid seals.
 (3) That the stacks are free of obstructions.

(b) One of the methods listed below may be used to test for correct set pressure. Test connections should include a gauge or deadweight tester so arranged that the pressure at which the device becomes operative may be observed and recorded.
 (1) The pressure may be increased in the segment until the device is activated. During the tests, care should be exercised to ensure that the pressure in the segment protected by the relief device does not exceed the limit in §192.201.
 (2) The pressure from a secondary pressure source may be added to the pilot or control line until the device is activated.
 (3) The device may be transported to a shop for testing and returned to service. When the device is to be shop-tested or otherwise rendered inoperative, adequate overpressure protection of the affected segments should be maintained during the period of time the relief device is inoperative.

(c) See §192.743 for reviewing and calculating, or testing, the required capacity of relief devices.

## 6 FINAL INSPECTION

The final inspection procedure should include the following.

(a) A check by personnel who are qualified (see Subpart N) for proper position of all valves. Special attention should be given to regulator station bypass valves, relief device isolating valves, and valves in control, sensing, and supply lines.

(b) Restoration of all locking and security devices to proper position.

# §192.740

## Pressure regulating, limiting and overpressure protection – Individual service lines directly connected to production, gathering, or transmission pipelines.

*[Effective Date: 03/12/21]*

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

**(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: (1) A service line that only serves engines that power irrigation pumps; (2) A service line included in a distribution integrity management plan meeting the requirements of subpart P of this part; or (3) A service line directly connected to either a production or gathering pipeline other than a regulated gathering line as determined in § 192.8 of this part.**

**[Amdt. 192-123, 82 FR 7998, Jan. 23, 2017]**

**GUIDE MATERIAL**

*No guide material available at present.*

# §192.741

## Pressure limiting and regulating stations: Telemetering or recording gages.

*[Effective Date: 11/12/70]*

**(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gages 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 gages 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.**

**GUIDE MATERIAL**

**1 MAINTENANCE OF TELEMETERING INSTRUMENTS, RECORDING GAUGES, AND RECORDS**

1.1 *Operation, testing, and maintenance of instruments*.
All instruments used for telemetering or recording pressures should be operated in accordance with the manufacturers' recommended instructions, and should be inspected and tested in accordance with said instructions at intervals not exceeding 1 year.

1.2 *Review of recording charts*.
Each operator should review the recorded pressure readings either at the time of inspection or shortly after the removal of the gauge chart from the gauge. Each operator should review the recorded pressure readings for the following.
(a) Any indication of abnormal operating condition (i.e., high- or low-pressure).
(b) Proper operation by the recording instrument.
(c) Proper operation of pressure regulating devices.

1.3 *Identification of pressure charts*.
The operator should indicate on each pressure recording chart the following information.
(a) Name of the operator.
(b) Location of recording gauge-station name or number or both.
(c) Date and time of recorded pressure readings.

(d) Any tests performed on the gauge during the recorded period.

*1.4 Retention of pressure records*.
All records showing the recorded pressure readings should be retained in accordance with requirements of the governmental agency that has jurisdiction over the operator, unless the operator requires their retention for a longer time period.

## 2 DISTRIBUTION SYSTEMS SUPPLIED BY MORE THAN ONE PRESSURE REGULATOR STATION (§192.741(a))

*2.1 Telemetering or recording pressure gauge*.
Each operator should install and maintain telemetering or recording pressure gauges at some points in the system. The location of the gauges is dependent upon the design of the system, and therefore, should be at points that would best indicate an abnormal operating condition.

*2.2 Temporary recording gauges at low-pressure points*.
Each operator should give consideration to installing temporary recording gauges at various locations in the distribution system at suspected or anticipated low-pressure points. The data compiled or derived from these gauges will assist the operator in determining the adequacy of the system design. These gauges should remain until the suspected condition is:
(a) Shown to be satisfactory; or
(b) Corrected.

*2.3 Additional telemetering or recording pressure gauges*.
If the system is such that installed gauges cannot adequately indicate the pressure in the distribution system, the operator should give consideration to installing additional telemetering or recording pressure gauges at selected points to assist in maintaining the maximum and minimum allowable operating pressures as required by §§192.619, 192.621, and 192.623.

## 3 DISTRIBUTION SYSTEMS SUPPLIED BY ONE PRESSURE REGULATOR STATION (§192.741(b))

*3.1 Telemetering as early warning agent*.
Telemetering of pressure or flow may be used as an early warning agent to disclose system failures or malfunctions. The following parameters should be considered to determine if a telemetering system is feasible and practical.
(a) Response time of operating personnel to the source of the telemetered signal.
(b) The magnitude of pressure drop or flow increase which would indicate a system failure.
(c) Design limits of the telemetering system to properly respond to the criteria established in (b) above.
(d) Recognition of possible failures to which the telemetry would not respond.
(e) Seasonal changes in normal pressure or flow requirements, which may require resetting the alarm limits.
(f) The complexity of the telemetry system to be installed. The system could vary from a simple high-low pressure switch alarm to a more sophisticated system transmitting signals to a computer.
(g) Location of the telemetered alarm at a center manned 24 hours a day having the capability to alert appropriate operating personnel.

On the basis of the foregoing factors, determine whether (1) the telemeter is feasible, and if so, (2) determine whether it is practical in relation to cost, probability of pipeline failure, proximity to the operating headquarters, risk analysis, and system safety.

*3.2 Monitoring of single feed distribution system operations*.
Even though the number of source points required to monitor a single feed distribution system may be fewer than the number required for a distribution system fed by more than one pressure regulator station, the guide material in 2.1, 2.2, and 2.3 above should be considered.

**4 ABNORMAL OPERATING CONDITIONS (§192.741(c))**

If an abnormal operating condition is indicated, the operator should:

(a) Investigate and determine if pressure regulating and auxiliary control equipment is in satisfactory operating condition. Any unsatisfactory condition found by inspection or test should be immediately corrected.
(b) Investigate and determine if the pressure recording device is in proper operating condition. Any unsatisfactory condition found by inspection or test should be corrected as soon as practical.
(c) Investigate the distribution system in the vicinity of a high-pressure or low-pressure condition.

# §192.743

## Pressure limiting and regulating stations: Capacity of relief devices.

*[Effective Date: 10/08/04]*

**(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. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-55, 51 FR 41633, Nov. 18, 1986; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-96, 69 FR 27861, May 17, 2004 with Amdt. 192-96 DFR Confirmation, 69 FR 54248, Sept. 8, 2004]**

**GUIDE MATERIAL**

**1 CAPACITY DETERMINATION BY IN-PLACE TESTING**

*1.1 Determination of actual flow*.

The capacity of the relief valve system can be determined by direct measurement under full flow conditions or by determining a coefficient through limited flow tests that can be used in calculating the full capacity. References for performing the appropriate tests include the following.

(a) UG-131 of the ASME Boiler and Pressure Vessel Code, Section VIII (see §192.7).
(b) API RP 525, "Testing Procedure for Pressure-Relieving Devices Discharging Against Variable Back Pressure" (Revised 1960; Discontinued).

*1.2 Demonstrating adequate capacity*.

(a) A test may be conducted by simulating conditions of maximum pressure and supply volume conditions for the pressure control source of the protected segment and minimum flow conditions on the discharge side of the source. Under these conditions the pressure control source should be wide open. Adequate capacity is determined if the relief device prevents the downstream pressure from exceeding that permitted by §192.201.

(b) When conducting such a test, care must be taken to maintain service and to prevent overpressuring any components in the system.

**2 CAPACITY DETERMINATION BY CALCULATION**

*2.1 Determination of required relief capacity*.

(a) The maximum possible flow through the source supplying the system being protected should be determined.
  (1) When the source is controlled by the operator, recognized engineering formulas may be used to make the calculations based on data published by, or otherwise obtained from, the manufacturer of the equipment used as a pressure source or pressure control component.
    (i) A lesser capacity than calculated above is acceptable if calculations of flow in the piping on the inlet or outlet of the equipment show a lesser throughput to be the maximum.
    (ii) Data used in these calculations should be selected so that the capacity calculated will represent the maximum throughput in actual operations, including emergencies. Minimum demand may be considered.
  (2) When the operator does not have control of the source, information should be obtained to adequately determine the maximum flow and pressure capacity of that source. This information may then be used as the basis for relief capacity requirements.

(b) When more than one pressure regulating or compressor station feeds a pipeline, relief capacity based on complete failure of the largest capacity regulator or compressor should be adequate. The operator should consider subsequent failures that may be caused by an initial failure.

*2.2 Determination of relief device capacity*.
See 2 of the guide material under §192.201.

**3 REDETERMINATION**

A redetermination of the required relief capacity should be made whenever there are changes in the system that could increase the supply of gas from the source, the capacity of the control device, or the ability of the relief device to handle the required flow.

**4 GATHERING LINES**

(a) The MAOP of gathering lines could be protected by equipment that is located outside of the regulated segment of pipeline. While the relief device might not be subject to Part 192 due to its location, individual devices that provide overpressure protection or isolation of downstream regulated segments could be regulated by function.
(b) Although not required for non-regulated devices, operators of Type B gathering lines should consider performing routine capacity calculations for relief devices.

## §192.745

### Valve maintenance: Transmission lines.

*[Effective Date: 10/15/03]*

**(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.**

**(c) For each remote-control valve (RCV) installed in accordance with §§ 192.179 or 192.634, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with § 192.631(c) and (e).**

**(d) For each alternative equivalent technology installed on an onshore pipeline under §§192.179(e), 192.179(f), or 192.634 that is manually or locally operated (i.e., not a rupture-mitigation valve (RMV), as that term is defined in § 192.3):**

**(1) Operators must achieve a valve closure time of 30 minutes or less, pursuant to §192.636(b), through an initial drill and through periodic validation as required in paragraph (d)(2) of this section. An operator must review and document the results of each phase of the drill response to validate the total response time, including confirming the rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification.**

**(2) Within each pipeline system and within each operating or maintenance field work unit, operators must randomly select a valve serving as an alternative equivalent technology in lieu of an RMV for an annual 30-minute-total response time validation drill that simulates worst-case conditions for that location to ensure compliance with § 192.636. Operators are not required to close the valve fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance with drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar year, with intervals not to exceed 15 months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph.**

**(3) If the 30-minute-maximum response time cannot be achieved during the drill, the operator must revise response efforts to achieve compliance with § 192.636 as soon as practicable but no later than 12 months after the drill. Alternative valve shut-off measures must be in place in accordance with paragraph (e) of this section within 7 days of a failed drill.**

**(4) Based on the results of response-time drills, the operator must include lessons learned in:**

**(i) Training and qualifications programs;**

**(ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and**

**(iii) Any other areas identified by the operator as needing improvement.**

**(5) The requirements of this paragraph (d) do not apply to manual valves who, pursuant to §192.636(g), have been exempted from the requirements of §192.636(b).**

**(e) Each operator must develop and implement remedial measures to correct any valve installed on an onshore pipeline under §§192.179(e), 192.179(f), or 192.634 that is indicated to be inoperable or unable to maintain effective shut-off as follows:**

**(1) Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain effective shut-off. An operator must request an extension from PHMSA in accordance with §192.18 if repair or replacement of a valve within 12 months would be economically, technically, or operationally infeasible; and**

**(2) Designate an alternative valve acting as an RMV within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Such valves are not required to comply with the valve spacing requirements of this part.**

**(f) An operator using an ASV as an RMV, in accordance with §§192.3, 192.179, 192.634, and 192.636, must document and confirm the ASV shut-in pressures, in accordance with 192.636(f), on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required, on a calendar year basis not to exceed 15 months.**

**[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

## GUIDE MATERIAL

### 1 INSPECTION AND MAINTENANCE

(a) Each operator should review the valve manufacturer's recommendations and develop an appropriate maintenance program.
(b) Valves should be operated to the extent necessary to establish operability during an emergency. When operating the valve, precautions should be taken to avoid a service outage or overpressuring the system.
(c) When maintenance is completed, the operator should verify that the valves are in the proper position.
(d) When inspecting or maintaining valves, the location reference data contained in the operator's records should be compared with field conditions. Changes, such as referenced landmarks, street alignment, and topography, should be noted and incorporated in the records.
(e) Gathering line emergency valves.
  (i) While a valve protecting a Type A gathering line might not be subject to Part 192 due to its location, it could be regulated by function.
  (ii) Although not required, operators should consider performing routine inspections on valves protecting Type B gathering lines.

**2 PRECAUTIONS**

If a valve is to be partially operated, precautions should be taken to avoid a service outage or overpressuring the system. Such precautions might include the following.
(a) Documenting the valve type (e.g., plug, gate, ball) and the direction and number of turns to operate the valve.
(b) Verifying the orientation of the valve in relation to the valve stops.
(c) Monitoring downstream pressure for any variation from normal operating pressure.
(d) Qualified personnel (see Subpart N) and system operating SME, if necessary, should be involved in the inspection or adjustment of any valve that could affect pressure regulating equipment or other pressure sensing equipment.
(e) See guide material under §192.739 for equipment associated with pressure regulation and overpressure protection.

**3 INOPERABLE VALVES**

The following actions should be considered if a valve is found inoperable.
(a) Repair the valve to make it operable.
(b) Designate another valve or valves to substitute for the inoperable valve that will provide a similar level of effectiveness for isolating the line section. Consideration should be given to the following.
  (1) Spacing requirements as prescribed in §192.179.
  (2) Updating records for emergency shutdown and future maintenance requirements.
  (3) Informing employees of the change to the isolation or emergency shutdown plan.
(c) Replace the valve.

# §192.747

## Valve maintenance: Distribution systems.

*[Effective Date: 10/15/03]*

**(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 46850, Oct. 21, 1982; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]**

**GUIDE MATERIAL**

**1 INSPECTION AND MAINTENANCE**

Valves should be checked for adequate lubrication and proper alignment to permit the use of a key, wrench, handle, or other operating device. Where applicable, the valve box or vault should be cleared of any debris that would interfere with or delay the operation of the valve.

**2 PRECAUTIONS**

If a valve is to be partially operated, precautions should be taken to avoid a service outage or overpressuring the system. Such precautions might include the following.

(a) Documenting the valve type (e.g., plug, gate, ball) and the direction and number of turns to operate the valve.
(b) Verifying the orientation of the valve in relation to the valve stops.
(c) Monitoring downstream pressure for any variation from normal operating pressure.
(d) Qualified personnel (see Subpart N) and system operating SME, if necessary, should be involved in the inspection or adjustment of any valve that could affect pressure regulating equipment or other pressure sensing equipment.
(e) See guide material under §192.739 for equipment associated with pressure regulation and overpressure protection.

**3 INOPERABLE VALVES**

The following actions should be considered if a valve is found inoperable.

(a) Repair the valve to make it operable.
(b) Designate another valve or valves to substitute for the inoperable valve that will provide a similar level of effectiveness for isolating the desired area. Consideration should be given to the following.
    (1) Updating records for emergency shutdown and future maintenance requirements.
    (2) Informing employees of the change to the isolation or emergency shutdown plan.
(c) Replace the valve.

**4 IDENTIFICATION AND RECORD VERIFICATION**

(a) See §192.181 for additional information on identifying valves necessary for the safe operation of a distribution system.
(b) See guide material under §192.745 regarding verification of records with current field data.

## §192.749

## Vault maintenance.

*[Effective Date: 07/13/98]*

**(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.**

**[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-85, 63 FR 37500, July 13, 1998]**

**GUIDE MATERIAL**

**1 APPLICABILITY**

The following guide material applies to vaults that contain pressure regulating or pressure limiting equipment and have a volumetric internal content of 200 cubic feet or greater. Section 192.749 does not apply to valve access vaults, other underground vault-type structures that have a volumetric internal content of less than 200 cubic feet, or underground vault-type structures that do not contain pressure regulating or limiting equipment (e.g., emergency isolation valve, hand-hole access type). See guide material §192.3 for a definition of vault.

## 2 HAZARDOUS ATMOSPHERES

Hazardous atmospheres might exist in such vaults due to leakage from components within the vault, or from seepage of gases (e.g., natural gas, nitrogen) or other vapors, fumes, or mists (e.g., gasoline) from outside the vault.

## 3 DEVELOPMENT OF SAFETY PROCEDURES

Procedures for appropriate safety measures should be developed and should include the following.

*3.1 Procedures prior to entry*.

(a) Engine exhausts should be kept away from the vault opening.
(b) All possible sources of ignition should be kept away from the work area, except as may be required in the performance of the work. See §192.751.
(c) Sufficient safety equipment (e.g., dry chemical fire extinguishers, breathing apparatus, safety harnesses) should be available in the work area.
(d) Flashlights, lighting fixtures, and extension cords should be of a type approved for hazardous atmospheres.
(e) Before the cover is removed, the vault atmosphere should be tested for combustible gas. Use the holes or pry holes, or lift the edge of the cover slightly to admit the testing probe. In double cover manholes, it will be necessary to remove the outer cover and partially lift the inner cover to make the test.
(f) Immediately after removal of the cover, tests for combustible gas and for oxygen deficiency should be made at various levels that can be reached from the surface.
(g) Results of the tests made in accordance with 3.1(e) and (f) above should determine the procedures to be followed.
    (1) *Combustibles at 60% of the Lower Explosive Limit or Less (e.g., 3.0% natural gas in air or less)*. The vault may be entered without breathing apparatus after establishing, by test, that a safe oxygen level exists, or if continuous forced draft ventilation is maintained. Forced draft ventilation is superior to suction draft ventilation.
    (2) *Combustibles in excess of 60% of the Lower Explosive Limit*. The vault should not be entered unless ventilation maintains combustible level below 60% of the Lower Explosive Limit and a safe oxygen level exists. However, in the event the vault cannot be adequately ventilated and the facility cannot be taken out of service to effect necessary repairs, the vault may be entered with the use of an approved breathing apparatus and safety harness.

*3.2 Procedures for vault entry and while working in the vault*.

(a) Ladders should be used when entering or leaving vaults.
(b) Upon entering a vault, workers should inspect or test the interior for abnormal or hazardous conditions.
(c) When workers enter vaults, at least one person should remain on the surface and, under ordinary circumstances, not leave the work location. In the event workers require a breathing apparatus and safety harness in accordance with 3.1(g)(2) above, at least two persons should remain on the surface (one being in a position to continuously observe activity in the vault).
(d) When workers enter vaults, the atmosphere should be retested for combustible gases and oxygen deficiency at intervals not to exceed one hour, or instrumentation providing continuous monitoring should be used.
(e) Only approved flashlights or lighting equipment should be used. Electrical connections and disconnections should be made outside the vault. See guide material under §192.751.

*3.3 Procedures for vaults with restricted openings.*

Safety measures should be considered for vaults that have restricted openings and are greater than 4 feet deep. OSHA regulations could be a source of safety information.

**4 INSPECTION AND REPAIRS**

(a) If gas is detected prior to entry or while working in the vault, or if the operator can hear or smell gas, the operator should follow the appropriate guide material in 3 above.

(b) In accordance with the operator's applicable O&M and safety procedures, the operator should enter or remain in the vault:

(1) To further investigate, classify, and repair the leak as necessary

(2) To inspect equipment in the vault including the ventilating equipment and ensure it is adequately operating as intended.

(c) Whenever personnel enter a vault, periodic or continuous monitoring should be performed in vaults where the oxygen levels could be depleted (see 3 above).

**5 VAULT COVER INSPECTION (§192.749(d))**

Consider the following during the vault cover inspection.

(a) Vault cover lacks a locking device or other tamper-proof measures to prevent unauthorized access.
(b) Vault cover is damaged or deteriorated to the point it is unsafe to open.
(c) Vault cover is damaged or deteriorated to the point it is unsafe to support expected external loads.
(d) Vault cover is not identified as housing gas facilities, as might be required by the operator or local regulatory authority.
(e) Any other hazardous condition that might be detrimental to public safety as deemed by the operator.

## §192.750

### Launcher and receiver safety.

*[Effective Date: 07/01/2020]*

**Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (*e.g.* inspection tools, scrapers, or spheres), if pressure has not been relieved.**

**[Amdt. 192-125, Oct. 01, 2019]**

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-125.*

## §192.751

### Prevention of accidental ignition.

*[Effective Date: 11/12/70]*

**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.**

## GUIDE MATERIAL

## 1 GENERAL

*1.1 Smoking and open flames*.

Smoking and open flames should be prohibited in the following locations.

(a) In structures or areas containing gas facilities where possible leakage or presence of gas constitutes a hazard of fire or explosion.

(b) In the open when accidental ignition of gas-air mixture might cause personal injury or property damage.

*1.2 Accidental electric arcing*.

To prevent accidental ignition by electric arcing, the following should be considered.

(a) Flashlights, portable floodlights, extension cords, and any other electrically powered tool or equipment should be of a type approved for use in hazardous atmospheres. Care should be taken to ensure that electrical connections and disconnections are not made, and are prevented from occurring, in hazardous atmospheres.

(b) Internal combustion engines that power trucks, cars, compressors, pumps, generators, and other equipment should not be operated in suspected or known hazardous atmospheres.

(c) Bonding to provide electrical continuity should be considered around all cuts separating metallic pipes that may have natural gas present. This bond should be installed prior to cutting and maintained until all reconnections are completed or a gas free environment exists. Bond cables should be installed in a manner to ensure that they do not become detached during construction and that they provide minimal electrical resistance between pipe sections.

*1.3 Static electricity on plastic pipe.*

A static electric charge can build up on both the inside and outside of plastic pipe due to the dielectric properties of plastic. Discharging of the static electricity going to ground can cause an arc that will cause ignition if a flammable gas-air mixture is present. In plastic pipe operations, it is essential to avoid the accumulation of a flammable gas-air mixture and the arcing of a static electrical discharge. When conditions exist such that a flammable gas-air mixture may be encountered and static charges may be present, such as when repairing a leak, squeezing-off an open pipe, purging, making a connection, etc., arc preventing safety precautions are necessary. The following should be considered.

(a) Leaking or escaping gas should be eliminated by closing valves or excavating and squeezing-off in a separate excavation at a safe distance from the escaping gas.

(b) If escaping gas cannot be effectively controlled or eliminated and it is necessary to work in an area of escaping gas, safety provisions should be considered such as dissipating or preventing the accumulation of a static electrical charge, venting the gas from the trench, and grounding those tools used in the area. Additionally, flame-resistant clothing treated to prevent static buildup and respiratory equipment should be used. Acceptable methods of dissipating or preventing the accumulation of static electricity include wetting the exposed area with an electrically conductive liquid (e.g., soapy water with glycol added when ambient temperatures are below freezing) and using a anti-static polyethylene (PE) film or wet non-synthetic cloth wound around or laid in contact with the entire section of exposed pipe and grounded with a brass pin driven into the ground. Commercially available electrostatic discharge systems may be considered as a means of eliminating static electricity from both the inside and outside of PE pipe.

(c) A plastic pipe vent or blowdown stack should not be used due to the possibility that venting gas with a high scale or dust content could generate an internal static electrical charge that could ignite the escaping gas. Metal vent stacks should be grounded before placement in the escaping gas stream. Venting should be done downwind at a safe distance from personnel and flammable material.

(d) To reduce potential sources of ignition, all tools, including squeeze-off tools, used in gaseous atmospheres should be grounded or the non-sparking type.

*1.4 Other sources of ignition*.

Care should be taken in selecting the proper hand tools for use in hazardous atmospheres and in handling tools to reduce the potential for a spark.

*1.5 Fire extinguishers.*

If escaping gas in the area of the work is possible, a fire extinguisher should be available upwind and adjacent to the area.

*1.6 Verification of the presence of gas.*

Prior to welding, cutting, or performing other work on isolated sections of gas piping, a check should be made with a gas detector for the presence of a combustible gas mixture inside the pipe. Work should begin only when safe conditions are indicated. If the work takes place over an extended period of time, the line should be periodically monitored to ensure that a combustible gas mixture does not accumulate.

*1.7 Accidental ignition of discharged gas.*

Operators should consider using the following measures to help avoid accidental ignition when gas is discharged in areas subject to public motor vehicle or pedestrian traffic.

(a) Posting warning signs.

(b) Directing motor vehicles and pedestrians away from the area by considering the following.
    (1) Law enforcement.
    (2) Traffic flaggers.
    (3) Signs (e.g., detour, road closed).
    (4) Barricades.

## 2 WELDING, CUTTING, AND OTHER HOT WORK

*2.1 General*.

Prior to welding, cutting, or other hot work in or around a structure or area containing gas facilities, a thorough check should be made with a gas detector for the presence of a combustible gas mixture. Prior to entering pipe, tanks, or similar confined spaces, appropriate instruments should be used to ensure a safe, breathable atmosphere. Work should begin only when safe conditions are indicated. The atmosphere should be tested periodically for oxygen deficiency and combustible gas mixtures.

*2.2 Pipelines filled with gas*.

When a pipeline or main is to be kept full of gas during welding or cutting operations, the following are recommended.

(a) A slight flow of gas should be kept moving toward the cutting or welding operation.

(b) The gas pressure at the site of the work should be controlled by suitable means.

(c) All slots or open ends should be closed with tape, tightly fitted canvas, or other suitable material immediately after a cut is made.

(d) Two openings should not be uncovered at the same time.

*2.3 Pipelines containing air*.

(a) Before the work is started, and at intervals as the work progresses, the atmosphere in the vicinity of the zone to be heated should be tested with a combustible gas indicator or by other suitable means.

(b) Unless a suitable means (e.g., an air blower) is used to prevent a combustible mixture in the work area, welding, cutting or other operations that could be a source of ignition should not be performed on a pipeline, main, or auxiliary apparatus that contains air and is connected to a source of gas.

(c) When the means noted in 2.3(b) above are not used, one or more of the following precautions are suggested, depending upon the job site circumstances.
  (1) The pipe or other equipment upon which the welding or cutting is to be done should be purged with an inert gas.
  (2) The pipe or other equipment upon which the welding or cutting is to be done should be continuously purged with air in such a manner that a combustible mixture does not form in the facility at the work area.

## 3 ISOLATING PIPELINE SEGMENTS ON PLANNED WORK TO MINIMIZE THE POTENTIAL OF IGNITION

*3.1 General*.

Planned work on gas facilities should incorporate procedures to shut off or minimize the escape of gas. No portion of a pipeline, large-diameter service line, or main should be cut out under pressure, unless the flow of gas is shut off or minimized by the use of line valves, line plugging equipment, bags, stoppers, or pipe squeezers. Where 100% shutoff is not feasible, the following precautions are recommended.

(a) Plan the job to minimize the escape of gas and sequence steps to limit the time and amount of gas to which personnel are exposed.
(b) Ensure that the size and position of the cut allows the gas to vent properly even with an employee in the excavation.
(c) Protect personnel working in a gaseous atmosphere under an overhang, in a tunnel, or in a manhole.

*3.2 Isolating pipeline segments*.

(a) Preliminary action. The operator should conduct a prework meeting(s) to review the following with the personnel involved.
  (1) The method of isolation.
  (2) The purpose of each activity.
  (3) Drawings, procedures, and schematics, as applicable.
  (4) Responsibilities of each individual, including the designation of an individual to be in charge of the operation.
(b) Isolation precautions.
  (1) The operator should ensure that the isolation equipment is appropriate and sized correctly for the job.
  (2) Isolation equipment left unattended should have a positive means of preventing unauthorized operation.
  (3) Positive means should be provided at the work site to alert and protect personnel from unintentional pressuring. Consideration should be given to the use or installation of items such as:
    (i) Relief valves.
    (ii) Rupture discs.
    (iii) Pressure gauges.
    (iv) Pressure recorders.
    (v) Vents.
    (vi) Pressure alerting devices.
    (vii) Other pressure detecting devices.
  (4) Isolation equipment should be inspected and maintained prior to use.
  (5) Temporary closures capable of withstanding full line pressure should have a means to determine pressure buildup, such as gauges and vents.
  (6) Consideration should be given to the following to prevent the uncontrolled release of liquid hydrocarbons when cutting into offshore pipelines or other pipelines that might contain significant quantities of these liquids.
    (i) The elevation difference between the blowdown valve and cut location.

(ii) The impact of water displacement on liquid hydrocarbons in those instances where water may enter into the pipeline segment.

(c) Monitoring isolated segments.

(1) Monitoring procedures should be established based on the pressure, volumes, closures, and other pertinent factors.

(2) Personnel assigned to operate isolation equipment should have a means to determine pressure buildups, such as gauges and vents.

(3) Personnel monitoring at remote locations should have communication with the work site and the individual in charge of the operation.

## 4 NOTIFICATIONS PRIOR TO PURGE OR BLOWDOWN

*4.1 Public officials*.

Local public officials should be notified prior to a purge or blowdown in those situations where the normal traffic flow through the area might be disturbed, or where it is anticipated that there will be calls from the public regarding the purge or blowdown.

*4.2 Public in vicinity of gas discharge*.

The public in the vicinity of the gas discharge should be notified prior to a purge or blowdown, if it is anticipated that the public might be affected by the process. The primary considerations for determining the need for notification are noise, odor, and the possibility of accidental ignition.

## 5 REFERENCE

A reference is AGA XR603, "Plastic Pipe Manual for Gas Service," Chapter VI – Maintenance, Operation and Emergency Control Procedures.

# §192.753

## Caulked bell and spigot joints.

*[Effective Date: 10/15/03]*

**(a) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psi (172 kPa) 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 25 psi (172 kPa) gage or less and is exposed for any reason must be sealed by a means other than caulking.**

**[Amdt. 192-25, 41 FR 23679, June 11, 1976; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]**

### GUIDE MATERIAL

No guide material necessary.

## §192.755

### Protecting cast-iron pipelines.

*[Effective Date: 06/01/76]*

**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).**

**[Issued by Amdt. 192-23, 41 FR 13588, Mar. 31, 1976]**

**GUIDE MATERIAL**

See guide material under §192.614, and Guide Material Appendices G-192-16 and G-192-18.

## §192.756

### Joining plastic pipe by heat fusion: equipment maintenance and calibration.

*[Effective Date: 01/22/19]*

**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.**

**[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]**

*No guide material available at present.*

## §192.761

### (Removed.)

*[Effective Date: 02/14/04]*

## 5 CONDUCT ASSESSMENT

(a) In accordance with §192.929(b)(2), the operator is required to use an assessment specified in ASME B31.8S, Appendix A3. This appendix does allow other methods to be used (Appendix A3.1) in addition to those listed in Appendix A3.4.
(b) In accordance with ASME B31.8S, Appendix A3.4, the operator is required to prepare a written inspection, examination, and evaluation plan. For guidance in writing a plan, see guide material under §192.925 (ECDA) and §192.927 (ICDA). An operator may already have written procedures for many of the required plan components. Existing procedures may be modified to meet the additional requirements of SCCDA.
(c) When planning excavations for SCCDA, consider coordinating with other excavations such as those for ECDA and ICDA. See 5.2(g) of the guide material under §192.925.
(d) Examination and evaluation.
    (1) If a direct examination reveals no disbonded coating on a coated pipeline, SCC is not considered to be present. Therefore, it is not recommended to remove coating that is not disbonded.
    (2) The operator is required to remove disbonded coating and, as with bare pipe, the surface must be inspected for SCC using magnetic particle inspection (MPI) with a documented inspection procedure (ASME B31.8S, Appendix A3.4.1(c)). When necessary, the method of coating removal is a function of the coating type. Care should be taken when removing coating to ensure that evidence of SCC is not damaged. See NACE SP0204, Table B1 for additional information on selection of surface preparation guidelines for MPI.
    (3) Additional data elements to consider during excavation can be found in 5.3 of the guide material under §192.925, and NACE SP0204, Table 2, "Data Collected at a Dig Site in an SCCDA Program and Relative Importance."

## 6 REMEDIATION

(a) No SCC indications found. If SCC is not found at the most likely location(s), an operator can conclude the integrity assessment and set the reassessment interval. See Table 192.939iv of the guide material under §192.939 regarding reassessment intervals for SCC.
(b) SCC indications found.
    (1) When SCC indications are detected, at least one of the following three mitigation methods is required to be used (ASME B31.8S, Appendix A3.4.1(d)(2)).
        (i) *Evaluate repair or removal methods for SCC.* Industry research, such as the PRCI Pipeline Repair Manual (PR-218-9307), addresses repair methods for SCC.
        (ii) *Hydrostatically test the covered segment.* See ASME B31.8S, Appendix A3.4.2.
        (iii) *Engineering critical assessment (ECA).* An ECA is a process to document the evaluation of the risks of SCC and provide a technically valid plan that demonstrates satisfactory pipeline safety performance. The ECA should consider the defect growth mechanisms for the SCC process. For additional guidance on performing an ECA, see the following references.
            (A) OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study," Michael Baker, Jr., Inc., January 2005
            (B) ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas."
    (2) The 2010 edition of ASME B31.8S provides guidance for addressing indications of SCC in Tables A-1, SCC "Crack Severity Criteria" and A-2, "Response to Bell Hole SCC Indications."

## 7 RECORDKEEPING

(a) SCCDA records should be documented in a clear, concise, and workable manner.
(b) Records may be maintained at a central location or at multiple locations.

(c) Records may be maintained either electronically, as paper copies, or in any other appropriate format.
(d) See NACE SP0204, Section 7 for additional guidance on recordkeeping.

## 8 REFERENCES

(a) ASME B31.8S-2010, "Managing System Integrity of Gas Pipelines." [*The 2010 Edition is not incorporated by reference.*]
(b) ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas."
(c) NACE Publication 35103, "External Stress Corrosion Cracking of Underground Pipelines."
(d) NACE SP0204, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology."
(e) National Energy Board (Canada), Report of the Inquiry MH-2-95, "Stress Corrosion Cracking on Canadian Oil and Gas Pipelines," December 1996.
(f) OPS Advisory Bulletin ADB-03-05 (68 FR 58166, Oct. 8, 2003; see Guide Material Appendix G-192-1, Section 2).
(g) OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study," Michael Baker, Jr., Inc., January 2005.
(h) PRCI L52047, "Pipeline Repair Manual," PR-218-9307
(i) PRCI L52043, "SCC Initiation Susceptibility Ranking/Screening," PR-273-0328.
(j) Stress Corrosion Cracking Recommended Practices, 2nd Edition (CEPA).

# §192.931

## How may Confirmatory Direct Assessment (CDA) be used?

*[Effective Date: 03/06/15]*

**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.**

**[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]**

## GUIDE MATERIAL

## 1 DISCOVERY OF CONDITION

(a) The operator is expected to define "discovery of condition" in its written integrity management program because that date sets the schedule for evaluation and remediation. Conditions may be discovered as soon as the assessment is completed. Some of these may require immediate action. However, the operator generally has no more than 180 days after completing an assessment to discover a condition that presents a potential threat to the integrity of the pipeline. The operator should document the date each condition was discovered.
(b) Assessment is considered complete after fully executing any one of the following.
  (1) Hydrostatic test.
  (2) Last in-line inspection (ILI) tool run of a scheduled series of tool runs.
  (3) Last direct examination associated with direct assessment.
  (4) Completion of field activities associated with "other technology" for which an operator has provided timely notification as required by §192.921(a)(4).
(c) "Discovery of condition" is dependent on the integrity assessment technique that is used as shown in Table 192.933i.
(d) "Discovery of condition" under §192.933(b) is not necessarily the same as "Discovery" under §191.25. See 3(a) below.

| ESTABLISHING "DISCOVERY OF CONDITION" DATE | |
|---|---|
| **Assessment Technique** | **Discovery of Condition Typically Occurs When:** |
| In-Line Inspection (ILI) | The operator receives a graded or characterized set of indications, or other data, from the inspection device and an analysis indicates a condition exists that could be a threat to pipeline integrity. |
| Pressure Testing | A leak that indicates a condition that could be a threat to pipeline integrity is observed or a failure occurs. |
| Direct Assessment | Direct examination or analysis of direct examination data indicates a condition that is a threat to pipeline integrity. The analysis should be completed as soon as practical after the direct examination. |

**TABLE 192.933i**

## 2 SCHEDULE FOR EVALUATION AND REMEDIATION

*2.1 Immediate repair conditions.*

(a) "Immediate repair conditions" are indications that a defect has failed or may be close to failure. These conditions require action within 5 days of discovery. Although §192.933 uses the term "immediate repair condition," a repair is not always required within the 5-day period. A temporary reduction of pressure (see §192.933(a)) will allow the pipeline to continue to operate.
(b) For immediate repair conditions that result from analysis of ILI data, an evaluation of the indication must be conducted within five days of discovery.
(c) For ILI and DA, immediate repair conditions include any of the following.
  (1) An indicated corrosion defect that yields a predicted failure pressure of less than 1.1 times the MAOP.
  (2) A dent that has any indication of metal loss, cracking, or a stress riser (see Table 192.933ii).
  (3) An indication of stress corrosion cracking.

(4) A metal loss indication affecting a detected longitudinal seam in low-frequency ERW pipe or pipe produced by electric flash welding.
(5) Other indications that might be expected to cause immediate failure or, in the judgment of the operator, require immediate action.

(d) For ECDA, "immediate indications" only become "immediate repair conditions" when direct examination indicates a defect that meets one of the above criteria.
(e) For repair information, see guide material under 192.713.

2.2 *One-year conditions.*
Dents requiring repair within one year are listed in Table 192.933ii.

2.3 *Scheduled conditions.*
Corrosion indications are required to be analyzed for predicted failure pressure in accordance with ASME B31G, PRCI PR-3-805 (RSTRENG) (see §192.7 for IBR for both), or equivalent method. The failure pressure ($P_f$) is divided by the MAOP to determine a safety factor. The safety factor and operating percent of SMYS determine the maximum time interval for evaluation and remediation. The maximum time interval for responding to scheduled defects may be obtained from ASME B31.8S-2004, Section 7, Figure 4 (see §192.7 for IBR).

2.4 *Monitored conditions.*
Dents that can be monitored are included in Table 192.933ii.

| **REMEDIATION OF DENTS** | | | |
|---|---|---|---|
| **Pipe Size** | **Dent Location** | **Description** | **Schedule** |
| **Any** | Any | A dent that contains a crack, stress riser, or has metal loss. | Immediate |
| **Less than 12"** | Any | A dent with a depth[1] greater than 0.25 inches that affects a girth weld or longitudinal weld seam, with no engineering analysis. | One year |
| | Any | A dent with a depth[1] greater than 0.25 inches that affects a girth weld or longitudinal weld seam and engineering analysis demonstrates critical strain levels are not exceeded. | Monitor |
| | Top 2/3 of pipe | A smooth dent with a depth[1] greater than 0.5 inches, with no engineering analysis. | One year |
| | Top 2/3 of pipe | A dent with a depth[1] greater than 0.5 inches, and engineering analysis demonstrates critical strain levels are not exceeded. | Monitor |
| | Bottom 1/3 of pipe | A dent with a depth[1] greater than 0.5 inches. | Monitor |

**TABLE 192.933ii (Continued)**

**REMEDIATION OF DENTS (Continued)**

| Pipe Size | Dent Location | Description | Schedule |
|---|---|---|---|
| **Equal to or greater than 12"** | Any | A dent with a depth[1] greater than 2% of the pipe diameter that affects a girth weld or longitudinal weld seam, with no engineering analysis. | One year |
| | Any | A dent with a depth[1] greater than 2% of the pipe diameter that affects a girth weld or longitudinal weld seam and engineering analysis demonstrates critical strain levels are not exceeded. | Monitor |
| | Top 2/3 of pipe | A smooth dent with a depth[1] greater than 6% of the pipe diameter with no engineering analysis. | One year |
| | Top 2/3 of pipe | A dent with a depth[1] greater than 6% of the pipe diameter and engineering analysis demonstrates critical strain levels are not exceeded. | Monitor |
| | Bottom 1/3 of pipe | A dent with a depth[1] greater than 6% of the pipe diameter. | Monitor |

[1] See 2 of the guide material under §192.309 for measuring the depth of a dent.

**TABLE 192.933ii**

## 3 PRESSURE REDUCTION

(a) Conditions that require a reduction in operating pressure may constitute a safety-related condition. See the guide material under §191.25 where the term "Discovery" is referenced for the purpose of reporting safety-related conditions. This is not necessarily the same as "Discovery of condition" under §192.933. See 1(d) above.
(b) If a pressure reduction exceeds 365 days, the operator is required (§192.933(a)(2)) to provide notification (see §192.18). The notification must (§192.933(a)(2)) include the reasons for not remediating within 365 days, and provide technical justification that the pressure reduction is still adequate.
  (1) Reasons for the delay in remediation could include preventing a service outage or a delay in obtaining any of the following.
    (i) Materials.
    (ii) Permits.
    (iii) Right-of-way.
  (2) Technical justification that the pressure reduction is still adequate should consider one or more of the following.
    (i) Effect of continued corrosion.
    (ii) Environmental changes.
    (iii) Additional pressure cycles.
    (iv) Class location changes.
    (v) Validation of the existing pressure reduction.
(c) If the existing pressure reduction is no longer adequate, the operator should do one of the following.
  (1) Make further reduction in operating pressure.
  (2) Repair or replace the pipe.

(3) Take pipeline out of service.

## §192.935

### What additional preventive and mitigative measures must an operator take?

*[Effective Date: 03/06/15]*

**(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) *Risk analysis for gas releases and protection against ruptures.* If an operator determines, based on a risk analysis, that a rupture-mitigation valve (RMV) or an alternative equivalent technology would be an efficient means of adding protection to a high-consequence (HCA) area in the event of a gas release, an operator must install the must install the RMV or alternative equivalent technology. In making that determination, an operator must, at least, consider the following factors — timing 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. An RMV or alternative equivalent technology installed under this paragraph must meet all**

**of the other applicable requirements in this part.**

**(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.**

**(f) *Periodic evaluations.* Risk analyses and assessments conducted under paragraph (c) of this section must be reviewed by the operator and certified by a senior executive of the company, for operational matters that could affect rupture-mitigation processes and procedures. Review and certification must occur once per calendar year, with the period between reviews not to exceed 15 months, and must also occur within 3 months of an incident or safety-related condition, as those terms are defined at §§ 191.3 and 191.23, respectively.**

**[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004, Amdt. 192-95 Correction & Petition for Reconsideration, 69 FR 18228, Apr. 6, 2004 and Amdt. 192-95 Correction, 69 FR 29903, May 26, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]**

## GUIDE MATERIAL

### 1 ADDITIONAL PREVENTIVE AND MITIGATIVE (P&M) MEASURES (§192.935(a) and (c))

To comply with §192.935, an operator must conduct a risk analysis of all pipelines within HCAs, and determine for each applicable threat on each covered segment whether any of the following (which exceed the requirements of other subparts of Part 192) will prevent pipeline failure or mitigate the consequences of such a failure.

Some activities performed as requirements for additional preventative and mitigative measures may also be used to satisfy similar program requirements under §§192.614, 192.615, 192.616, and 192.620(d)(2).

(a) Installation of an automatic shut-off valve (ASV) or a remote control valve (RCV).
   (1) To comply with §192.935(c), an operator must consider the following factors in determining if an ASV or RCV would be an efficient means of adding protection in an HCA.
      (i) Swiftness of leak detection. Example: There may be no advantage to installing an ASV or RCV on segments where adequate SCADA or other monitoring methods allow for quick operator response to leakage.
      (ii) Shutdown capabilities in the area. Example: An ASV or RCV might not make shutdown any faster or easier in locations where adequate valving and easy access already exists.
      (iii) Type of gas. Example: An ASV or RCV might mitigate the environmental impact of leakage on a pipeline carrying heavier-than-air gases.
      (iv) Operating pressure. Example: Higher-pressure lines hold a larger volume of gas. An ASV

or RCV on such a line may reduce the volume of release and potential for ignition.
- (v) Potential release rate. Example: Installing an ASV or RCV may affect the duration of the potential release rate.
- (vi) Pipeline profile. Example: Heavier-than-air gases can pool in low elevation spots. An ASV or RCV in such locations may allow faster shut off and, therefore, less accumulation of gas.
- (vii) Potential for ignition. Example: Areas that have known sources of ignition (e.g., foundries) might benefit from an ASV or RCV.
- (viii) Location of nearest response personnel. Example: Locations where operator response is timely may not benefit from the installation of an ASV or RCV.

(2) An operator may also consider the following.
- (i) Seasonal weather restrictions that can impede access.
- (ii) Depth of pipe as it relates to access for squeeze-off.
- (iii) River crossings or other geographical features that affect access for maintenance or response.
- (iv) Proximity of the HCA to existing valves.
- (v) Population density.
- (vi) Wide pressure fluctuations due to normal operating conditions (e.g., power plant locations).
- (vii) Maintenance, reliability, and cost-benefit issues.

(b) Installation of computerized monitoring and leak detection systems.
An operator may consider the following, which could provide earlier leak or pipeline rupture detection.
- (1) Increasing the locations monitored by SCADA.
- (2) Automating data gathering from other monitoring devices such as pressure transmitters.

(c) Replacing pipe with that of heavier-wall thickness, which is more resistant to damage from external forces.

(d) Providing additional training on response procedures.
An operator may consider the following.
- (1) Increasing the frequency of emergency response training.
- (2) Conducting tabletop or field drills.
- (3) Hiring a third party with expertise in emergency response to conduct training.
- (4) Attending emergency response training offered by industry associations.

(e) Conducting drills with local emergency responders.
The operator may consider the following.
- (1) Including the drill as part of liaison meetings with emergency responders.
- (2) Working with local multi-agency, emergency coordination groups.
- (3) Incorporating the drill into local fire or police academy curriculum.

(f) Implementing additional inspection and maintenance programs.
The operator may consider the following.
- (1) Increasing leak survey frequencies.
- (2) Increasing patrol frequencies.
- (3) Using procedures with more stringent criteria than required by the Regulations.
- (4) Increasing facility inspection frequencies.

## 2 THIRD-PARTY DAMAGE (§192.935(b)(1))

To comply with §192.935(b)(1) for the specific threat of third-party damage, an operator must do the following.

(a) Qualify personnel to conduct the following activities related to work the operator is conducting in a covered segment.
- (1) Locating the pipeline.
- (2) Marking the pipeline.
- (3) Directly supervising known excavation work. A qualification for this activity might include the following.
  - (i) Recognition of line-locate markings.
  - (ii) Knowledge of one-call requirements.

(iii) Knowledge of operator's applicable procedures, including emergency response.
(iv) Understanding the risks of various excavation methods.
(4) Other activities that could adversely affect the integrity of the pipeline.

(b) Use a central database to collect the following.
(1) Excavation damage information for covered and non-covered segments. This might include the following.
(i) Number of leaks or ruptures.
(ii) Number of known damages not resulting in leaks or ruptures.
(iii) Excavation method.
(iv) Name of excavator causing damage.
(2) Root-cause analysis data to identify targeted P&M measures for HCAs. This might include the number of damages where:
(i) No line locate was requested.
(ii) Line was incorrectly marked.
(iii) Line was not marked.
(iv) Construction procedures were not followed correctly (e.g., exposing lines during boring).
(3) Damage data that is not DOT reportable (reference Part 191 requirements). This might include known items such as the following.
(i) Dents.
(ii) Gouges.
(iii) Coating damage.
(iv) Damage to pipeline supports or river anchors.

(c) Participate in a one-call program wherever there are covered segments.

(d) Monitor excavations on covered segments. An operator may want to consider the following.
(1) Mapping HCAs so field personnel can easily recognize when they are in an area that requires monitoring.
(2) Creating a business process that alerts the appropriate departments of pending excavations.
(3) Working with the local One-Call Center to notify excavators and operators when monitoring is required.
(4) Training line locators to notify appropriate personnel when they know work will take place in an HCA.
(5) Documenting excavation monitoring using one or more of the following.
(i) Time card accounting.
(ii) Special forms.
(iii) Time-stamped electronic data.
(iv) Maps.

(e) When there is physical evidence of an excavation near a covered segment that the operator did not monitor, either excavate the area or conduct an aboveground survey (e.g., DCVG) as defined in NACE SP0502-2010 (see §192.7 for IBR). Examples of how to identify an encroachment might include the following.
(1) New pavement patches.
(2) Heavy equipment on site.
(3) Disturbed earth.
(4) New structures requiring excavation (e.g., fence posts, telephone poles, buildings, slabs).
(5) Exposed pipe.
(6) New landscaping.
(7) One-call documentation.

## 3 OUTSIDE FORCE DAMAGE (§192.935(b)(2))

To comply with §192.935(b)(2) for the specific threat of outside force damage (e.g., earth movement, floods, unstable suspension bridge), an operator must take additional measures to minimize the consequences of outside force.

(a) The measures include the following.
(1) Increasing the frequency of patrols. This may allow faster recognition of damage.
(2) Adding external protection. This might include the following.

(i) Installing fencing or other barriers to impede earth movement.
(ii) External slabs or additional cover.
(iii) Add erosion protection such as riprap.
(3) Reducing external stress. This might include the following.
(i) Installing expansion joints.
(ii) Removing overburden.
(4) Relocating the pipeline to an area with less exposure to outside forces. This might include lowering or raising the pipeline.
(5) Conducting inline inspections to determine whether geometric deformation has occurred.
(b) An operator may also consider installing the following.
(1) River anchors where appropriate.
(2) Elevated relief or vent stacks on regulator stations.
(3) Additional bridge hangers or pipe supports.

## 4 PIPELINES OPERATING BELOW 30 PERCENT SMYS (§192.935(d))

Pipelines operating below 30% SMYS have additional requirements as addressed below. For guidance related to these additional requirements, see Appendix E to Part 192.
(a) For all Class locations in an HCA, the following apply.
(1) Qualify personnel to conduct the following activities related to work the operator is conducting in a covered segment.
(i) Locating the pipeline.
(ii) Marking the pipeline.
(iii) Directly supervising known excavation work. A qualification for this activity might include the following.
(A) Recognition of line-locate markings.
(B) Knowledge of one-call requirements.
(C) Knowledge of operator's applicable procedures, including emergency response.
(D) Understanding the risks of various excavation methods.
(iv) Other activities that could adversely affect the integrity of the pipeline.
(2) Participate in a one-call program wherever there are covered segments.
(3) Either monitor excavations near the pipeline, or conduct patrols on a bi-monthly frequency. Any indication of unreported construction activity requires an investigation to determine if any damage has occurred.
(b) For Class 3 or Class 4 locations outside of an HCA.
(1) Qualify personnel to conduct the following activities related to work the operator is conducting in covered segment.
(i) Locating the pipeline.
(ii) Marking the pipeline.
(iii) Directly supervising known excavation work. A qualification for this activity might include the following.
(A) Recognition of line-locate markings.
(B) Knowledge of one-call requirements.
(C) Knowledge of operator's applicable procedures, including emergency response.
(D) Understanding the risks of various excavation methods.
(iv) Other activities that could adversely affect the integrity of the pipeline.
(2) Participate in a one-call program wherever there are covered segments.
(3) Either monitor excavations near the pipeline, or conduct patrols on a bi-monthly frequency. Any indication of unreported construction activity requires an investigation to determine if any damage has occurred.
(4) Perform semi-annual leak surveys. For unprotected or cathodically protected pipe where electrical surveys are impractical, perform quarterly leak surveys.
(c) See Table 192.935i.

## 5 PLASTIC TRANSMISSION LINES (§192.935(e))

Plastic transmission lines have additional requirements as follows.

(a) Qualify personnel to conduct the following activities related to work the operator is conducting in a covered segment.
  (1) Locating the pipeline.
  (2) Marking the pipeline.
  (3) Directly supervising known excavation work. A qualification for this activity might include the following.
    (i) Recognition of line-locate markings.
    (ii) Knowledge of one-call requirements.
    (iii) Knowledge of operator's applicable procedures, including emergency response.
    (iv) Understanding the risks of various excavation methods.
  (4) Other activities that could adversely affect the integrity of the pipeline.
(b) Participate in a one-call program wherever there are covered segments.
(c) Monitor excavations on covered segments. An operator may want to consider the following.
  (1) Mapping HCAs so field personnel can easily recognize when they are in an area that requires monitoring.
  (2) Creating a business process that alerts the appropriate departments of pending excavations.
  (3) Working with the local One-Call Center to notify excavators and operators when monitoring is required.
  (4) Training line locators to notify appropriate personnel when they know work will take place in an HCA.
  (5) Documenting excavation monitoring by using one or more of the following.
    (i) Time card accounting.
    (ii) Special forms.
    (iii) Time-stamped electronic data.
    (iv) Maps.
(d) When there is physical evidence of an encroachment on a covered segment that the operator did not monitor, excavate the area to determine if any damage has occurred. Examples of how to identify an encroachment include the following.
  (1) New pavement patches.
  (2) Heavy equipment on site.
  (3) Disturbed earth.
  (4) New structures requiring excavation (e.g., fence posts, telephone poles, buildings, slabs).
  (5) Exposed pipe.
  (6) New landscaping.
  (7) One-call documentation.
(e) See Table 192.935i.

| ADDITIONAL P&M MEASURES FOR TRANSMISSION PIPELINES OPERATING BELOW 30 PERCENT SMYS AND PLASTIC TRANSMISSION LINES | | | | | |
|---|---|---|---|---|---|
| **Location** | **General Requirements** | **Use Qualified Personnel** | **Participate in one-call** | **Monitor Excavations or Additional Patrol** | **Additional Leak Survey** |
| Class 1 & 2 in HCA | X | X | X | X | |
| Class 1 & 2 outside HCA | | | | | |
| Class 3 & 4 in HCA | X | X | X | X | |
| Class 3 & 4 outside HCA | | X | X | X | X |
| Plastic Transmission | X | X | X | X (monitor only) [1] | |

[1] The option of patrolling is not available for plastic transmission lines.

**TABLE 192.935i**

## §192.937

### What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

*[Effective Date: 07/10/06]*

**(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.**

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## GUIDE MATERIAL

## 1 GENERAL

See the guide material under §192.939 for reassessment intervals.

## 2 EVALUATION FOR COVERED SEGMENTS

One of the goals of periodic evaluation is to determine what is changing and what actions are needed to maintain safe operations. Periodic evaluations are based on integrating information, identifying changes to pipeline threats, and updating risk analyses. This evaluation is intended to support the identification of changes needed to assessment frequencies, assessment types, and preventive and mitigative (P&M) measures.

*2.1 Frequency.*

When determining the frequency, the operator should consider the following.

(a) The number and types of changes that are occurring. For example, if there are no changes to HCAs, MAOPs, or personnel, a longer interval may be appropriate.
(b) For pipe subject to low stress reassessment, the requirement to evaluate external corrosion data for:
  (1) Cathodically protected lines at least once every 7 years (§192.941(b)(1)), or
  (2) Unprotected pipe at least once every 18 months (§192.941(b)(2)).
(c) For pipe subject to low stress reassessment, the requirement to evaluate internal corrosion data at least once every 7 years (§192.941(c)(3)).
(d) The evaluation intervals should not exceed the assessment intervals listed in ASME B31.8S-2004, Section 5, Table 3 (see §192.7 for IBR).
(e) Items that might trigger an evaluation (e.g., incidents, new data) before the scheduled evaluation.

2.2 *Data integration.*

Use information collected through assessment, remediation, and P&M measures to update records where default values were used, or that have been determined to be inaccurate or incomplete.

2.3 *Threat identification.*

Use information collected through assessment, remediation, and P&M measures to identify new threats or to evaluate the severity of existing threats. Additional changes to threats may be identified through the evaluation of the following.

(a) Failures.
(b) Incidents.
(c) Abnormal operations.
(d) Lessons learned.
(e) Performance metrics.

2.4 *Risk analysis.*

(a) Use information collected through assessment, remediation, and P&M measures to determine if the risk ranking is consistent with the results.
(b) Use information collected through data integration, assessment, remediation, and P&M measures to update the risk model.
(c) Changes to segments included in risk assessment may be identified through the evaluation of the following.
  (1) System modifications.
  (2) HCA changes.
  (3) O&M activities.
  (4) Operational changes.
  (5) Environmental changes.

2.5 *Subsequent actions driven by periodic evaluation.*

(a) Identify changes required to assessment intervals.
(b) Confirm that assessment methods are applicable for the identified threats.
(c) If current methods are not effective for current threats, determine correct assessment methods and reassess applicable segments.
(d) Determine the effectiveness of current P&M measures.
(e) Determine the need for changes to existing P&M measures or implementation of additional measures.
(f) If an operator changes the criteria for grading ILI anomalies, the operator should review the impact of the changes on anomalies discovered during the prior assessments.
(g) If an operator changes ECDA or ICDA criteria for classifying indications, or for calculating the remaining life, the operator should review the impact of the changes on the results from the prior assessment.
(h) Evaluate the potential requirement for assessment and remediation of a threat on other pipeline segments as follows.
  (1) Similar pipeline segments when corrosion or seam issues are identified as a threat in a covered segment.
  (2) Similar covered segments when any threats are identified outside a covered segment.

## 3 ASSESSMENT METHODS

(a) For reassessment methods, see the guide material under §192.921.
(b) For CDA, see guide material under §192.931.
(c) For assessment conducted to satisfy MAOP reconfirmation, see guide material under §192.624(c). Such an assessment might not qualify as an integrity assessment under §192.937.

| **1.11 PLASTIC RELATED** (Continued) | | |
|---|---|---|
| ASTM D2837 | Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products | §192.3<br>§192.63<br>§192.121 |
| ASTM D2855 | Two-Step (Primer and Solvent Cement) Method of Joining Poly (Vinyl Chloride) (PVC) or Chlorinated Poly (Vinyl Chloride) (CPVC) Pipe and Piping Components with Tapered Sockets | §192.281 |
| ASTM F689 | Determination of the Temperature of Above-Ground Plastic Gas Pressure Pipe Within Metallic Casings (Withdrawn 2017) | |
| ASTM F1041 | Guide for Squeeze-Off of Polyolefin Gas Pressure Pipe and Tubing | §192.321 |
| ASTM F1290 | Electrofusion Joining Polyolefin Pipe and Fittings | §192.281 |
| ASTM F1563 | Tools to Squeeze-Off Polyethylene (PE) Gas Pipe or Tubing | §192.321 |
| ASTM F1804 | Standard Practice for Determining Allowable Tensile Load for Polyethylene (PE) Gas Pipe During Pull-in Installation | GMA G-192-15B |
| ASTM F1924 | Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing | §192.123 |
| ASTM F1948 | Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing | §192.123 |
| ASTM F1962 | Standard Guide for Use of Maxi-Horizontal Directional Drilling for Placement of Polyethylene Pipe or Conduit Under Obstacles, Including River Crossings | GMA G-192-15B |
| ASTM F1973 | Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems | §192.123 |
| ASTM F2620 | Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings | §192.281 |
| GRI-92/0147.1 | Users' Guide on Squeeze-Off of Polyethylene Gas Pipes | §192.321 |
| GRI-94/0205 | Guidelines and Technical Reference on Gas Flow Shut-Off in Polyethylene Pipes Using Squeeze Tools | §192.321 |
| GRI-96/0194 | Service Effects of Hydrocarbons on Fusion and Mechanical Performance of Polyethylene Gas Distribution Piping | §192.123 |
| PPI - Handbook of PE Pipe | *Note*: The following are available as individual chapters of the PPI Handbook of Polyethylene Pipe: | |
| | Chapter 8 – Above-Ground Applications for Polyethylene Pipe | §192.321 |
| | Chapter 12 – Horizontal Directional Drilling | GMA G-192-15B |

**Table Continued**

| | | |
|---|---|---|
| **1.11 PLASTIC RELATED** (Continued) | | |
| PPI TN-13 | General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings | §192.281<br>§192.283 |
| PPI TR-4 | PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe | §192.121 |
| PPI TR-9 | Recommended Design Factors and Design Coefficients for Thermoplastic Pressure Pipe | §192.123 |
| PPI TR-22 | Polyethylene Piping Distribution Systems for Components of Liquid Petroleum Gases | §192.121<br>§192.123 |
| PPI TR-33 | Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe | §192.281<br>§192.283 |
| PPI TR-41 | Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping | §192.123<br>§192.281<br>§192.283 |
| PPI TR-45 | Butt Fusion Joining Procedure for Field Joining of Polyamide-11 (PA-11) Pipe | §192.281 |
| PPI TR-50 | Generic Butt Fusion Joining Procedure for Field Joining of Polyamide-12 (PA12) Pipe | §192.281 |
| **1.12 PRESSURE & FLOW DEVICES** | | |
| API RP 520 P2 | Sizing, Selection and Installation of Pressure-Relieving Devices in Refineries, Part 2 Installation | §192.201 |
| API RP 525 | Testing Procedure for Pressure-Relieving Devices Discharging Against Variable Back Pressure (Revised 1960; Discontinued) | §192.743 |
| ASTM F1802 | Test Method for Performance Testing of Excess Flow Valves | §192.381 |
| ASTM F2138 | Standard Specification for Excess Flow Valves for Natural Gas Service | §192.381 |
| MSS SP-115 | Excess Flow Valves, NPS 1 1/4 and smaller, for Fuel Gas Service | §192.381 |
| MSS SP-142 | Excess Flow Valves for Fuel Gas Service, NPS 1½ through 12 | §192.381 |
| NBBI | Relieving Capacities of Safety Valves and Relief Valves Approved by the National Board (Discontinued) | §192.201 |

**Table Continued**

| **1.13 STRUCTURAL STEEL & SUPPORTS** | | |
|---|---|---|
| ASTM A36 | Carbon Structural Steel | |
| MSS SP-58 | Pipe Hangers and Supports - Materials, Design, Manufacture, Selection, Application, and Installation | §192.357 |

**Table Continued**

| **1.14 OTHER DOCUMENTS** (Continued) | | |
|---|---|---|
| AGA X69804 | Historical Collection of Natural Gas Pipeline Safety Regulations [Available from GPTC Secretary at AGA.] | Foreword Editorial Notes |
| AGA XK1801 | Purging Manual | §192.629 §192.727 |
| AGA XL0702 | Distribution Pipe: Repair and Replacement Decision Manual | §192.465 §192.703 GMA G-192-18 |
| AGA XL1001 | Classification of Locations for Electrical Installations in Gas Utility Areas | §192.163 |
| AGA XQ0005 | Odorization Manual | §192.625 |
| API Bulletin 5A2 | Bulletin on Thread Compounds for Casing, Tubing, and Line Pipe | §192.12 |
| API Bulletin E3 | Well Abandonment and Inactive Well Practices | §192.12 |
| API Guidance Document HF1 | Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines | §192.12 |
| API Guidance Document HF2 | Water Management Associated with Hydraulic Fracturing | §192.12 |
| API Guidance Document HF3 | Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing | §192.12 |
| API RP 5A3 | Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements | §192.12 |
| API RP 5A5 | Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe | §192.12 |
| API RP 5B1 | Gauging and Inspection of Casing, Tubing and Line Pipe Threads | §192.12 |
| API RP 5C1 | Recommended Practice for Care and Use of Casing and Tubing | §192.12 |
| API RP 10D-2 | Recommended Practice for Centralizer Placement and Stop-collar Testing | §192.12 |
| API RP 10F | Recommended Practice for Performance Testing of Cementing Float Equipment | §192.12 |
| API RP 13D | Rheology and Hydraulics of Oil-well Drilling Fluids | |
| API RP 14B | Design, Installation, Repair and Operation of Subsurface Safety Valve Systems | §192.12 |
| API RP 14E | Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems | §192.12 |

| **1.14 OTHER DOCUMENTS** (Continued) | | |
|---|---|---|
| GRI-91/0285.1 | Executive Summary: Technical Summary and Database for Guidelines for Pipelines Crossing Railroads and Highways | GMA G-192-15 |
| GRI-95/0171 | State-of-the-Art Review and Analysis of Guided Drilling Systems | GMA G-192-15B |
| GRI-96/0368 | Guidelines for the Application of Guided Horizontal Drilling to Install Gas Distribution Pipe | GMA G-192-15B |
| IAPMO | Uniform Plumbing Code | §192.141 |
| ISO 31000 | Risk Management – Guidelines | §192.12 |
| ISO 31010 | Risk Management – Risk assessment techniques | §192.12 |
| ISO 55000 | Asset Management | §192.12 |
| NCB | Subsidence Engineers' Handbook, National Coal Board Mining Department (U.K.), 1975 | GMA G-192-13 |
| NFPA 10 | Portable Fire Extinguishers | |
| NFPA 14 | Installation of Standpipe and Hose Systems | §192.141 |
| NFPA 24 | Installation of Private Fire Service Mains and Their Appurtenances | §192.141 |
| NFPA 54/ANSI Z223.1 | National Fuel Gas Code | Figure 192.11A<br>Figure 192.11B<br>§192.629 |
| NFPA 220 | Types of Building Construction | |
| NFPA 224 | Homes and Camps in Forest Areas (Discontinued) | §192.163 |
| NFPA 921 | Guide for Fire and Explosion Investigations | §192.617 |
| OTD-12/0003 | Cross Bore Best Practices – Best Practices Guide (prepared by GTI) | §192.614<br>GMA G-192-6 |
| PRCI L22279 | Further Studies of Two Methods for Repairing Defects in Line Pipe | §192.713 |
| PRCI L51406 | Pipeline Response to Buried Explosive Detonations | GMA G-192-16 |
| PRCI L51574 | Non-Conventional Means for Monitoring Pipelines in Areas of Soil Subsidence or Soil Movement | GMA G-192-13 |
| PRCI L51717 | Pipeline In-Service Relocation Engineering Manual | §192.703 |
| PRCI L51725 | Drilling Fluids in Pipeline Installation by Horizontal Directional Drilling-A Practical Applications Manual | GMA G-192-15A<br>GMA G-192-15B |
| PRCI L51740 | Evaluation of the Structural Integrity of Cold Field-Bent Pipe | §192.313 |
| **Table Continued** | | |

| 1.14 OTHER DOCUMENTS | | |
|---|---|---|
| PRCI L52047 | Pipeline Repair Manual (PR-218-9307) | §192.613<br>§192.713<br>§192.929 |
| PRCI PC-PISCES | Personal Computer - Pipeline Soil Crossing Evaluation System (PC-PISCES), Version 2.0 (Related to API RP 1102) | GMA G-192-15 |
| PRCI PR-277-144507 | Installation of Pipelines Using Horizontal Directional Drilling – An Engineering Design Guide | GMA G-192-15A<br>GMA G-192-15B |
| UL 723 | Test for Surface Burning Characteristics of Building Materials | §192.163 |

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# GUIDE MATERIAL APPENDIX G-192-9

(See guide material under §§192.143, 192.503, 192.505, 192.507, 192.509, 192.513, 192.619, 192.921, and Guide Material Appendix G-192-9A)

## TEST CONDITIONS FOR PIPELINES OTHER THAN SERVICE LINES

This table is presented as a compilation for the application of the test requirements in §§192.143, 192.503, 192.505, 192.507, 192.509, 192.513, and 192.619 as they apply to pipelines other than service lines. Additional guidance is provided in the notes.

| | **Other Than Plastic** | | | | **Plastic** |
|---|---|---|---|---|---|
| | **Under 30 Percent SMYS** | | | **30 Percent SMYS and Over** | |
| **Maximum Operating Pressure** | Less than 1 psig | 1 psig but less than 100 psig | 100 psig and over | All pressures | All pressures See Note (2) |
| **Test Medium** | Water<br>Air<br>Natural gas<br>Inert gas | Water<br>Air<br>Natural gas<br>Inert gas | Water<br>Air<br>Natural gas<br>Inert gas<br>See Note (3) | Water<br>Air<br>Natural gas<br>Inert gas | Water<br>Air<br>Natural gas<br>Inert gas<br>See Note (4) |
| **Maximum Test Pressure** | See Note (5) | See Note (5) | See Note (5) | See Note (5) | 3 x design pressure See Notes (6) and (7) |
| **Minimum Test Pressure** | 10 psig | 90 psig | Maximum operating pressure multiplied by class location factor in §192.619 (a)(2)(ii); See Note (3) | Maximum operating pressure multiplied by class location factor in §192.619 (a)(2)(ii); See Note (8) | 50 psig or 1.5 x maximum operating pressure, whichever is greater See Note (6) |
| **Minimum Test Duration** | See Note (9) | See Note (9) | 1 Hour and see Note (9) | 8 Hours (See Notes 8 & 9) | See Note (9) |

_Notes_:

(1) Determining whether a new segment of pipeline should be tested per §192.505 (30% SMYS and over) or per §192.507 (under 30% SMYS and at or above 100 psig) is dictated by the percent of SMYS at MAOP. Some pipelines, generally tested per §192.505, may contain segments or have connections that are tested per §192.507. For examples, see the following.

(a) If a new lateral is to be installed on a pipeline that operates over 30% SMYS, and the new lateral will operate with an MAOP that is less than 30% SMYS and at or above 100 psig, the new lateral is covered by §192.507, even though the header pipe might have been tested per §192.505.

(b) If a segment of transmission line is replaced with different-wall-thickness or stronger pipe that will operate with an MAOP below 30% SMYS, the replacement pipe segment is covered by §192.507, even if the majority of the pipeline has been tested per §192.505. However, in this situation the operator might consider testing in accordance with §192.505 to avoid possible issues with the following.

(i) Section 192.555(b)(1) and (b)(2), if the pipeline segment is uprated in the future to 30% SMYS or more.
(ii) Section 192.611(a)(1), if there is a confirmation or revision of the MAOP in the future due to a change in class location.

(2) Plastic pipe must be designed in accordance with §192.121.
(3) Whenever test pressure is 20% SMYS or greater and air, natural gas, or inert gas is the test medium, the line must be checked for leaks either by a leak test at a pressure greater than 100 psig but less than 20% SMYS or by walking the line while the pressure is held at 20% SMYS (§192.507(b)).
(4) See test temperature limitations for thermoplastic material in §192.513(d).
(5) Refer to §192.503(c) for limitations when testing with air, natural gas, or inert gas. There are no limitations for water test. For all test media, pipeline components must be taken into consideration when determining the maximum test pressure. When water is used as the test medium, it is essential to consider elevation differences to avoid overpressuring pipe at lower elevations in the segment. The pressure at lower elevations is determined by adding 0.43 psig for every foot of elevation differential to the test pressure, measured at a higher point.
(6) See 9.2 of the guide material under §192.321.
(7) Apply 2.5 x design pressure for PE or PA pipe using a design factor of 0.40.
(8) Refer to §192.505(a) for testing criteria covering pipelines located within 300 feet of buildings; §192.505(b) for compressor, measuring, and regulator stations; and §192.505(d) for fabricated units and short sections of pipe
(9) Duration determined by volumetric content of test section, test medium, test pressure, thermal effects, leak criteria, and instrumentation in order to ensure discovery of all potentially hazardous leaks. See 2 of the guide material under §192.509 and 4 of the guide material under §192.513.

# GUIDE MATERIAL APPENDIX G-192-9A

(See guide material under §§192.503, 192.505, 192.507, 192.513, 192.619, 192.921, and Guide Material Appendix G-192-9)

## PRESSURE TESTING GUIDELINES FOR TRANSMISSION INTEGRITY ASSESSMENTS

### 1 GENERAL

(a) Pressure testing new and existing steel and plastic (e.g., polyethylene) transmission pipelines is an assessment method that may be used by operators to confirm the integrity of pipelines from time-dependent threats (e.g., internal corrosion, external corrosion, stress corrosion cracking) and time-independent threats (e.g., manufacturing defects, excavation damage, construction damage).

(b) Pressure testing identifies, through failure, major defects that might threaten a pipeline's integrity or shows that no major flaws were revealed at the time of testing.

(c) Retesting should be considered for existing steel and plastic transmission pipelines when the following conditions exist.

(1) For steel pipelines, direct assessment is not an appropriate assessment method.
(2) In-line inspection tools are not appropriate or available.
(3) The pipe segment cannot accommodate the passage of in-line inspection tools due to restrictions in components, such as elbows or valves.
(4) Operator can maintain service to affected customers by having bi-directional system flow, an alternative supply source, or flexibility to take the pipe segment out of service.
(5) The gas flow or other pipeline conditions are not sufficient for running in-line inspection tools.

(d) See Guide Material Appendix G-192-9 for guidelines in selecting an appropriate pressure testing medium for steel and plastic transmission pipe segments.

(e) Consideration should be given to the qualifications required for personnel involved in pressure testing.

### 2 PRESSURE TESTING ADVANTAGES AND DISADVANTAGES

See guide material under §192.921 for the advantages and disadvantages of pressure testing new and existing steel and plastic pipelines.

### 3 PRESSURE TESTING OF STEEL TRANSMISSION PIPELINES

To optimize pressure testing as an integrity assessment tool, pressure testing of new and existing steel transmission pipelines should be conducted in accordance with Subpart J. Operators should consider testing at a higher pressure to detect the greatest number of flaws in the pipe segment.

*3.1 Pressure testing new steel transmission pipelines.*

(a) The test pressure may be above 100% SMYS at the lowest elevation to provide an adequate test pressure at the highest elevation to ensure fitness for service.

(b) When any portion is tested above 100% SMYS, a pressure-volume plot should be used to identify

(h) Water-body crossings where storm events, scouring, erosion, and dredging may alter the water bottom and change the depth of cover or expose the pipeline.

*2.3 Landfills and unstable soil.*

(a) Special consideration should be given when placing pipelines over landfill areas where the supporting fill may decompose. Mitigation measures include extra excavation and soil replacement or additional pipe support, such as slabs or casings.
(b) Long-wall or other mining underneath a pipeline may also lead to pipeline undermining or lack of support. Additional pipeline thickness, support bridging or slabs, or casings are all methods for consideration to mitigate these conditions.
(c) Areas subject to salt mining or sinkholes also deserve special consideration and may warrant one or more of the above solutions.

*2.4 Navigable waterways.*

(a) Where facilities will be installed in navigable waterways, the following should be considered.
  (1) Dynamic interaction between the water and bottom.
  (2) Flotation.
  (3) Scouring.
  (4) Erosion.
  (5) Impacts of major storms.
  (6) Potential dredging or anchoring activities.
(b) The use of models, such as hydrologic or land mass movement, might be beneficial.
(c) Additional information for work in harbors may be found in the National Research Council report, "Improving the Safety of Marine Pipelines" (1994), available online from National Academies Press (NAP) at www.nap.edu/read/2347.

## 3 MARKERS

In addition to the markers required by §192.707, consideration should be given to the following.

*3.1 General*.

(a) Installing line markers when a main, transmission line, or gathering line crosses or lies in close proximity to an area that, in the operator's judgment, is likely for excavation or damage. Typical examples include the following.
  (1) Drainage areas, such as flood-prone watercourses.
  (2) Irrigation ditches and canals subject to periodic excavations for cleaning out or deepening.
  (3) Drainage ditches subject to periodic grading, including those along roads.
  (4) Agricultural areas in which deep plowing or deep-pan breakers are employed.
  (5) Active drilling or mining areas.
  (6) Waterways or bodies of water subject to dredging or shipping activities.
  (7) Industrial or plant areas where excavating, earth moving, and heavy equipment operating activities are routine.
(b) If multiple pipeline facilities are within the same right-of-way or in the same area, each operator should mark its facilities in a way to eliminate confusion.
(c) When line markers cannot be placed directly over a pipeline due to lack of support, obstructions, or need to facilitate maintenance, the markers can be offset from a pipeline facility. Markers may include language such as "in the vicinity" or "in proximity of," but should not include specific distances.

*3.2 Transmission lines or gathering lines.*

(a) Installing markers at designated locations along the right-of-way, where practical, and wherever the party exerting control over the surface use of the land will permit such installations. Possible locations for line marker placement include the following.
   (1) Fence lines.
   (2) Angle points (i.e., bends and changes in pipeline direction).
   (3) Lateral take-off points.
   (4) Stream crossings (including bridges).
   (5) Where necessary to identify pipeline locations for patrols and leak surveys.
   (6) Where necessary for visibility of line markers in both directions.

(b) Using other methods of indicating the presence of the line where the use of conventional markers is not feasible, such as stenciled markers, cast-monument plaques, signs, or devices flush mounted in curbs, sidewalks, streets, building facades, or other appropriate locations.

(c) Installing temporary markers in areas of known heavy construction activity during the period that construction is in progress near existing or newly installed facilities, whether energized or not, particularly along highways, strip mines, and major excavations.

*3.3 Distribution lines*.

(a) While markers are not normally practical for distribution systems, indicating the presence of the line where special problems exist. See 3.2(b) above for alternate methods of marking.

(b) Installing temporary markers near existing or newly installed facilities, whether energized or not, particularly in areas of construction activity during the period that construction is in progress.

*3.4 Underwater pipeline.*

The use of buoys, poles, PVC markers, or other forms of temporary marking suitable for underwater pipelines. The type of marker chosen may be influenced by the depth of water, the types of vessels normally navigating the area, and other characteristics of the body of water.

## 4 MINING ACTIVITIES

(a) An operator should consider the effects of mining activities on pipeline facilities. The ground subsidence and soil overburden can cause significant stresses in pipelines.

(b) Long-wall mining is of special concern to pipeline operators. Long-wall mining involves complete removal of a coal seam, which is typically 200 to 1,500 feet underground. The roof of the mine collapses, and the collapse propagates to the surface.

(c) Operators with pipelines in areas of mining activity should consider the following actions.
   (1) Contact the mine operator to obtain the depth of coal, mined height, width of the seam, location and angle at which the activity passes under the pipeline, estimated schedule of mining activities, and previous subsidence profiles for other mines in the area.
   (2) Review the material properties of the pipe and associated valves and fittings, such as specification, rating or grade, wall thickness, SMYS, toughness, and seam and joint characteristics.
   (3) Perform subsidence calculations to predict the effect on the pipeline. One method of predicting subsidence was developed by the National Coal Board (NCB) and is reported in the "Subsidence Engineers' Handbook."
   (4) Reduce the operating pressure, or remove the pipeline from service, if warranted by predicted stress levels.
   (5) Expose the pipeline to limit overburden stress.
   (6) Monitor subsidence and strain levels. A reference for monitoring subsidence is PRCI L51574, "Non-Conventional Means for Monitoring Pipelines in Areas of Soil Subsidence or Soil Movement."

## 5 RECORDS

The location of facilities should be accurately mapped or otherwise recorded. The operator should ensure that maps or records used for locating facilities are updated whenever any changes are made.

## 6 DAMAGE PREVENTION CONSIDERATIONS

See Guide Material Appendix G-192-6 for damage prevention considerations while performing directional drilling or using other trenchless technologies. For damage prevention programs, see guide material under §192.614.

## 7 VEHICULAR DAMAGE

When determining a safe distance between an aboveground pipeline and vehicular traffic, consideration should be given to relevant factors, including the following.

(a) Type of public road (e.g., residential, federal or state highway, limited access highway).
(b) Type of driveway (e.g., residential, commercial, industrial).
(c) Type of off-road activity (e.g., four-wheeling, snowmobiling).
(d) Speed limit.
(e) Direction of traffic.
(f) Terrain.
(g) Natural or other barriers.
(h) Weather-related road conditions (e.g., ice, snow, snow removal).

## 8 OTHER

Consideration should be given to the following.

(a) Special precautions to protect buried control lines. See guide material under §192.199.
(b) Installing small-diameter, service line taps off large-diameter pipe so that the top of the tee is lower than the top of the pipe.
(c) The use of colored pipe wrap or coating so that the content of a pipe is readily evident. This coloring should conform to American National Standards where applicable.
(d) Where a plastic pipeline is installed in a common trench with electric underground lines, the need for additional clearance to prevent damage to the gas line from heating or a fault in the power line.
(e) Where future excavation (including grading) is likely, providing suitable means of warning (e.g., warning tape, marker paint, flags, temporary markers).
(f) For aboveground facilities, the potential for damage due to vandalism or other causes. Where unusual hazards may reasonably be expected, precaution should be taken to guard against them, such as guards, locks, protective barriers, or even an alternative or underground location.
(g) Responding to requests from third-party designers or planners for information regarding location of buried facilities. Such responses may include the following.
    (1) Providing maps.
    (2) Holding meetings.
    (3) Locating facilities in the field. See 2.7 of the guide material under §192.614.

    Recipients of such information should be reminded that notice of intent to excavate must still be provided in accordance with state or local regulations.

# GUIDE MATERIAL APPENDIX G-192-14

(See guide material under §§192.150, 192.465, 192.476, 192.605, and Subpart O)

## IN-LINE INSPECTION

### 1 BACKGROUND

In-Line Inspection (ILI) tools are a combination of mechanical and electrical components placed inside the pipeline to gather data on the condition of the pipeline and are commonly known as "smart pigs." Results of ILI inspections typically provide indications of defects with some characterization of the defect. The ILI data provides a screening tool for the operator to determine which defects need to be examined and in what time frame. Examination may also be needed to fully address a threat. For example, a metal loss tool may be able to determine a region of metal loss, but may not be able to determine if the metal loss was the result of corrosion, excavation damage, or mill defect.

Industry publications are listed below under References, which provide guidance on running ILI tools. When appropriate, this appendix will direct users to specific sections of the referenced documents. Table 1 provides a summary of the referenced documents and their topics.

### 2 DESIGN OF PIPELINES TO ACCOMMODATE ILI TOOLS

As required by §192.150, new or replacement transmission pipelines be designed to accommodate ILI tools. Type A gathering lines are exempt from this requirement (§192.9(c)). No exemption exists for Type B gathering lines (§192.9(d)). NACE SP0102, Section 7 provides guidance on new construction and the planning considerations for ILI, including the following.

(a) Multiple diameter pipelines, including offshore risers.
(b) Valves.
(c) High strength bends and fittings.
(d) Bend and bend radius.
(e) Consistent wall thickness.
(f) "Pup" joint installation.
(g) Collection of construction information.

### 3 TOOL SELECTION BASED ON THREATS

As required by §192.921(a)(1), if ILI is used to assess a covered segment, the ILI tool selection must comply with ASME B31.8S, Paragraph 6.2 (see §192.7 for IBR). A summary of ILI tools listed in ASME B31.8S and their applicable threats is presented in Table 192.919i of the guide material under §192.919. In selecting a tool, the pipeline features and operating conditions are also important. Additional guidance on tool selection is included in NACE SP0102, Section 3 and API Std 1163, Section 6.

Examination digs following an ILI run may be needed to fully address a threat. For example, a metal loss tool may be able to determine a region of metal loss, but may not be able to determine if the metal loss was the result of corrosion, excavation damage, or mill defect.

### 4 PIPELINE CONSIDERATIONS

The pipe configurations and operating conditions may limit the feasibility of ILI assessments. ILI tool vendors should be consulted for limitations on specific tools.

Cleaning pigs may need to be run prior to running an ILI tool. It might also be necessary to run dummy tools or gauge plates to determine if ILI tools will pass through the segment, or run caliper or geometry tools to evaluate bends and other restrictions prior to running the ILI tool. NACE SP0102, Section 4

provides guidance on the following physical and operational characteristics.
(a) Pipeline pressure and temperature.
(b) Launcher and receivers – work space and facility piping.
(c) Insertion devices, such as thermowells and probes.
(d) Pipe diameter and diameter changes.
(e) Wall thickness changes.
(f) Bend radius and back-to-back bends.
(g) Reduced-port and check valves.
(h) Internal coatings.
(i) Sales taps and feeds.
(j) Unbarred tees.
(k) Hydrate precautions.
(l) Pyrophoric precautions.
(m) Product flow and speed.
(n) Pipeline geometry.
(o) Pipeline cleanliness.

## 5 METHODS OF PROPULSION

Methods and mediums for propelling ILI tools include the following.
(a) Natural gas.
(b) Air or inert gas.
(c) Tethered.
(d) Self-propelled.
(e) Liquid medium.

*5.1 Natural gas.*
Natural gas is typically used to propel ILI tools. The advantage of natural gas is that the tool can be run without taking the pipeline out of service. Running the tool in natural gas may not be feasible if the line pressure or flow rates are too low or too high to control speed and gather accurate data.

*5.2 Air or inert gas.*
Air or nitrogen can be used to propel ILI tools if the existing gas pressure or flow rates do not permit running ILI tools using natural gas. The disadvantages of air or inert gas are that the pipeline must be taken out of service, additional costs might be incurred, and equipment is necessary for pumping and venting.

*5.3 Tethered.*
Tethered ILI tools are hooked to a cable and mechanically pulled through a pipeline. The advantage of tethered tools is that they do not require extensive launching and receiving facilities. The disadvantages of tethered inspections are that the pipeline generally must be taken out of service and that it is limited to relatively short segments, typically 2 miles or less. The length of pipe that can be inspected in a single pull may be further limited if there are numerous bends in the pipeline.

*5.4 Self-propelled.*
Self-propelled tools contain a motor used to drive the tool through the pipeline. An advantage of self-propelled tools is that the tool can be used in pipelines where the gas pressure is too low, or the gas flow rate is too slow, to propel standard tools. A disadvantage of self-propelled tools is the selection and available sizes are more limited than for other ILI tools.

*5.5 Liquid medium.*

Most ultrasonic ILI tools require a liquid couplant between the tool sensor and the pipe wall. This couplant can be supplied by running the tool in a liquid medium such as water or diesel fuel. The advantage of using liquid is that it allows the ultrasonic tools to be run in a gas pipeline and can provide better speed control. The disadvantages are that the pipeline must be taken out of service and a liquid must be delivered to the site, introduced into the pipeline, and later removed from the pipeline.

## 6 QUALIFICATION OF TOOLS

Prior to running an ILI tool, the operator and ILI service provider should agree on the performance specifications of the tool being used. Performance specifications state the detection threshold and probability of detection for various anomalies. Guidance on performance specifications is provided in API Std 1163, Sections 7 and 10, and Appendix A.

## 7 QUALIFICATION OF PERSONNEL

If ILI is used to assess pipe in a covered segment, §192.915(b) requires that persons who carry out ILI assessments and evaluate results be qualified. Guidance on personnel qualification is provided by ASNT ILI-PQ, "In-line Inspection Personnel Qualification and Certification."

## 8 LOGISTICS

When performing an ILI assessment, an operator typically contracts with an ILI vendor to perform the assessment. NACE SP0102, Section 5 provides guidance on the following items that should be considered in the contract.

(a) Defining scope of work.
(b) Liability issues.
(c) Health, safety, and environmental standards.
(d) Survey acceptance criteria.
(e) Items to include in report.
(f) Reporting schedule.

If ILI is used to assess pipe in a covered segment, §192.933 requires that operators must promptly, but no later than 180 days after performing an ILI assessment, discover conditions that could affect pipeline integrity. The prompt discovery requirement and the 180-day limit should be considered when determining the reporting schedule.

## 9 SCHEDULING CONSIDERATIONS

If ILI is used to assess pipe in a covered segment, the assessment deadline listed in §192.921 and reassessment interval in §192.937 must be considered when scheduling an ILI assessment. The use of ILI tools may require pipeline retrofitting, service interruption, permitting, and long lead-time for scheduling. These items should be considered in the scheduling. NACE SP0102, Section 6 provides guidance on the following items dealing with inspection scheduling.

(a) Site access conditions.
(b) Throughput or outage consideration.
(c) Personnel availability.
(d) Inspection run-time and multiple runs.
(e) Landowner considerations.
(f) Environmental permits and waste handling.
(g) Support equipment availability.
(h) Benchmarking and tracking.
(i) Contingency planning.

| Subpart | Section | Subject | Requirements |
|---|---|---|---|
| Part 191 | 191.5 | Telephonic notice of certain incidents | Notice |
| | 191.9 | Distribution system: Incident report | Report |
| | 191.11 | Distribution system: Annual report | Report |
| | 191.13 | Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines | Report |
| | 191.15 | Transmission and gathering systems: Incident report | Report |
| | 191.17 | Transmission and gathering systems: Annual report | Report |
| | 191.25 | Filing safety-related condition reports | Report |
| A General | 192.9 | Gathering line requirements | Inspection, test, written program, markers |
| | 192.10 | Outer continental shelf pipelines | Marker or schematic |
| | 192.12 | Underground natural gas storage facilities | Written procedures, integrity demonstration and verification, monitoring, records |
| | 192.13 | General requirements | Plans, procedures, programs, inspection, tests |
| | 192.14(a), (b) | Conversion to gas service | Written procedures, inspection, test, records |
| | 192.16 | Customer notification | Notice, records |

**Table Continued**

| Subpart | Section | Subject | Requirements |
|---|---|---|---|
| Materials B | 192.55(c) | Steel pipe | Visual examination, weldability test |
| | 192.63 | Marking of materials | Material marking |
| | 192.65 | Transportation of pipe | Test<br>NOTE: Pipe transported by railroad before November 12, 1970, may have been qualified for use by pressure testing, so the operator should retain records of those tests. |
| Pipe Design C | 192.107 | Yield strength (S) for steel pipe | Tensile strength test |
| | 192.112 | Additional design requirements for steel pipe using alternative MAOP | Records |
| Design of Pipeline Components D | 192.144 | Qualifying metallic components | Visual inspection |
| | 192.145 | Valves | Manufacturer’s test |
| | 192.149 | Standard fittings | Prototype test |
| | 192.150 | Passage of internal inspection devices | Petition approval |
| | 192.153 | Components fabricated by welding | Test |
| | 192.177(b) (4) & (5) | Additional provisions for bottle-type holders | Mill hydrostatic test, leak test |
| Welding of Steel in Pipelines E | 192.225 | Welding procedures | Written procedures, tests, records |
| | 192.227(b) | Qualification of welders and welding operators | Test |
| | 192.229(c) | Limitations on welders and welding operators | Test |
| | 192.241 | Inspection and test of welds | Visual inspection, test |
| | 192.243 | Nondestructive testing | Written procedures, test, records |
| | 192.245(b), (c) | Repair or removal of defects | Inspection, written procedures |

**Table Continued**

| | | | |
|---|---|---|---|
| F Joining of Materials other than by Welding | 192.273 | General (Joining of materials other than by welding) | Written procedures, inspection |
| | 192.281 | Plastic pipe (electrofusion) | Test |
| | 192.283 | Plastic pipe: Qualifying joining procedures | Written procedures, various tests |
| | 192.285 | Plastic pipe: Qualifying persons to make joints | Inspection, test, examination, qualification method |

**Table Continued**

| Subpart | Section | Subject | Requirements |
|---|---|---|---|
| G General Construction Requirements for Transmission Lines and Mains | 192.303 | Compliance with specifications or standards | Written specifications or standards |
| | 192.305 | Inspection: General | Inspection |
| | 192.307 | Inspection of materials | Visual inspection |
| | 192.313(b) | Bends and elbows (circumferential welds) | Test (nondestructive) |
| | 192.328 | Construction requirements for steel pipe using alternative MAOP | Records |
| H Customer Meters, Service Regulators, and Service Lines | 192.359(b) | Customer meter installations: Operating pressure | Test |
| | 192.381 | Service lines: Excess flow valve performance standards | Manufacturer's test, mark or identify |
| | 192.383 | Excess flow valve installation | Report |
| I Requirements for Corrosion Control | 192.455(b), (c), (f) | External corrosion control: Buried or submerged pipelines installed after 07/31/71 | Test, investigation |
| | 192.457 | External corrosion control: Buried or submerged pipelines installed before 08/1/71 | Test |
| | 192.459 | External corrosion control: Examination of buried pipeline when exposed | Examination, investigation |
| | 192.461(c) | External corrosion control: Protective coating | Inspection |
| | 192.465 | External corrosion control: Monitoring | Test, inspection, reevaluation, electrical survey |
| | 192.467 | External corrosion control: Electrical isolation | Inspection and test |

**Table Continued**

# GUIDE MATERIAL APPENDIX G-192-22

(See guide material under §192.9)

## GATHERING LINES REGULATORY REQUIREMENTS

| Code Requirement | Type A | Type B |
|---|---|---|
| | | |
| **PART 191** | | |
| 191.3 – Definitions | Yes | Yes |
| 191.5 – Immediate Notice of Certain Incidents | Yes | Yes |
| 191.13 – Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines | Yes | Yes |
| 191.15 – Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident Report | Yes | Yes |
| 191.17 – Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas facilities: Annual Report | Yes | Yes |
| 191.22 – National Registry of Pipeline and LNG Operators | Yes | Yes |
| 191.23 – Reporting Safety-Related Conditions | Yes | Yes |
| 191.25 – Filing Safety–Related Conditions Reports | Yes | Yes |
| | | |
| **PART 192** | | |
| 192.3 – Definitions | Yes | Yes |
| 192.5 – Class Locations | Yes | Yes |
| 192.18 - How to notify PHMSA | Yes | Yes |
| Subpart B – Materials | Yes | Yes (1) |
| 192.67 - Records: Material properties | Yes | No |
| Subpart C – Pipe Design | Yes | Yes (1) |
| 192.127 - Records: Pipe design | Yes | No |
| Subpart D – Pipeline Components | Yes | Yes (1) |
| 192.150 – Passage of internal inspection devices | Exempt (3) | Yes (1) |
| 192.205 - Records: Pipeline components | Yes | Exempt |
| Subpart E – Welding | Yes | Yes (1) |
| 192.227(c) – Qualification of Welders | Yes | Exempt (3) |
| Subpart F – Joining | Yes | Yes (1) |
| 192.285(e) – Plastic Pipe: Qualifying persons to make joints | Yes | Exempt (3) |
| Subpart G – Construction | Yes | Yes (1) |
| Subpart I - Corrosion Control | Yes | Yes |
| 192.493 - In-line inspection of pipelines | Exempt (3) | Exempt (3) |
| Subpart J – Testing | Yes | Yes (1) |
| 192.506 - Transmission lines: Spike hydrostatic pressure test | Exempt (3) | Exempt (3) |
| 192.603 – Records | Yes | No |
| 192.605 – Procedural manual for operations, maintenance, and emergencies | Yes | No |
| 192.607 - Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines | Exempt (3) | No |
| 192.609 – Change in class location: Required study | Yes | No |
| 192.611 – Change in Class Location: Confirmation or revision of maximum allowable operating pressure | Yes | No |
| 192.613 – Continuing Surveillance | Yes | No |
| 192.614 – Damage Prevention Program | Yes | Yes |
| 192.615 – Emergency Plans | Yes | No |
| 192.616 – Public Awareness | Yes | Yes |
| 192.617 – Investigation of Failures | Yes | No |

| | | |
|---|---|---|
| 192.619 – Maximum allowable operating pressure: Steel or plastic pipelines | Yes | Yes |
| 192.619(e) – MAOP in accordance with §192.624 | Exempt (3) | Exempt (3) |
| 192.624 - Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines | Exempt (3) | No |
| 192.625 – Odorization of gas | Yes | No |
| 192.627 – Tapping pipelines under pressure | Yes | No |
| 192.629 – Purging of pipelines | Yes | No |
| 192.631 – Control room management | Yes | No |
| 192.632 - Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines. | Exempt (3) | No |
| 192.703 – General (Hazardous leaks) | Yes | Yes (only (c)) |
| 192.705 – Transmission lines: Patrolling | Yes | No |
| 192.706 – Transmission lines: Leakage Surveys | Yes | Yes |
| 192.707 – Line markers for mains and transmission lines | Yes | Yes |
| 192.709 – Transmission lines: Record keeping | Yes | No |
| 192.710 - Transmission lines: Assessments outside of high consequence areas | Exempt (3) | No |
| 192.712 - Analysis of predicted failure pressure | Exempt (3) | No |
| 192.727 – Abandonment or deactivation of facilities | Yes | No |
| 192.731 – Compressor stations: Inspection and testing of relief devices | Yes | No |
| 192.736 – Compressor stations: Gas detection | Yes | No |
| 192.739 – Pressure limiting and regulating stations: Inspection and testing (2) | Yes | No |
| 192.743 – Pressure limiting and regulating stations: Capacity of relief devices (2) | Yes | No |
| 192.745 – Valve maintenance: Transmission lines (2) | Yes | No |
| 192.749 – Vault maintenance | Yes | No |
| 192.750 - Launcher and receiver safety | Yes | No |
| 192.751 – Prevention of accidental ignition | Yes | No |
| | | |
| Subpart N – Qualification of Pipeline Personnel | | |
| Class 2 locations | Describe program | No |
| Class 3 & 4 locations | Yes | No |
| Subpart O – Gas Transmission Pipeline Integrity Management | Exempt (3) | No |
| Part 199 – Drug and Alcohol Testing | Yes | Yes |
| | | |
| Type B gathering lines must have written programs for: | | |
| Damage Prevention | | |
| Public Awareness | | |
| 192.303 – New Construction Comprehensive Written Specifications | | |
| *Notes:* | | |
| 1. Type B gathering lines that are new, replaced, relocated or otherwise changed must comply | | |
| 2. Regulated device may be located outside of actual regulated pipeline segment | | |
| 3. Specifically exempt as per §192.9(c) and (d) | | |