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October 16, 2023

Dear *Guide* Purchaser,

Enclosed is ANSI/GPTC Z380.1, *Guide for Gas Transmission, Distribution, and Gathering Piping Systems,* 2022 Edition, which includes Addenda 1, 2, and 3.

Your purchase entitles you to receive future notification of the issuance of addenda. Addenda are formatted to enable the replacement of pages in your *Guide* with updated pages. Addenda are available for free downloading from the GPTC webpage at www.aga.org/gptc or paper copies may be purchased at https://www.aga.org/aga-publications for a nominal fee.

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

Sincerely,

Secretary
GPTC Z380

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

2022 EDITION

Addendum 3, October 2023

The changes in this edition 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 were no Federal Regulation update(s) for this period. 19 GPTC transactions affected 22 sections of the Guide.

Editorial updates include application of the Editorial Guidelines, adjustments to page numbering, and adjustment of text on pages. Only significant editorial updates are marked. Editorial updates as indicated "EU" affected 6 sections of the Guide. Most sections were impacted by page adjustments throughout the guide.

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 TR YY-XX: GPTC transaction with new or updated guide material EU: editorial update

Guide Section	Reason for Change	Pages to be Removed	Replacement Pages
Title Page	EU	i/ii	i/ii
Contents	EU	vii/viii	vii/viii
Front	TR 20-19	xiv/xv	xiv/xv

Part 191			
191.5	TR 20-02	5/6	5/6
191.25	EU	13/14	13/14
Part 192			
PART A 192.3	TR 16-35, 19-52, EU	21/21a, 27/28, 29/30	21/21a, 27/28, 29/30
192.11	TR 16-23	49/50	49/50, 50a/51
PART D 192.150	TR 19-43	109/110	109/110
192.204	TR 19-04	145/146	145/146
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PART F 192.285	TR 19-46	169/170	169/170
PART G 192.321	TR 19-04	181/182, 187/188	181/181a, 182/183, 187/187a, 188/189
PART H			

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192.383	TR 16-34	217/218, 219/220	217/218, 218a/219, 220/220a
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PART L 192.605	TR 19-45	287/288	287/287a, 288/289
192.613	EU	305/305a, 306/307	305/305a, 306/307
192.616	TR 17-18	331/332, 333/334	331/331a, 332/333, 334/335
192.617	TR 21-06	333/334, 335/335a, 336/337	334/335, 335a/335b, 336/336a, 336b/337
192.624	TR 19-52	359/360	359/359a, 359b/359c
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PART O 192.925	TR 20-16	509/510	509/510
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GMA G-192-17	TR 16-34, 19-45, 19-46, 21-02	845/846,846a/847, 851/852	845/846, 846a/847, 851/852
GMA G-192-21	TR 22-08	863/863a, 863g/863h	863/863a, 863g/863h
INDEX	TR 21-06	873/874, 875/876	873/874, 875/876

Guide for Gas Transmission, Distribution, and Gathering Piping Systems

2022 Edition

Addendum 3, October 2023

An American National Standard

Author:
Gas Piping Technology Committee (GPTC) Z380
Accredited by ANSI

Secretariat:
American Gas Association

Approved by
American National Standards Institute (ANSI)
Date: March 1, 2022

ANSI GPTC Z380.1-2022,
Catalog Number: Z380

PLEASE NOTE

Addenda to this Guide will also be issued periodically to enable users to keep the Guide up-to-date by replacing the pages that have been revised with the new pages. It is advisable, however, that pages which have been revised be retained so that the chronological development of the Federal Regulations and the Guide is maintained.

CAUTION

As part of document purchase, GPTC (using AGA as Secretariat) will try to keep purchasers informed on the current Federal Regulations as released by the Department of Transportation (DOT). This is done by periodically issuing addenda to update both the Federal Regulations and the guide material. It is the responsibility of the purchaser to obtain a copy of any addenda. Addenda are posted on the Committee's webpage at www.aga.org/gptc. The GPTC assumes no responsibility in the event the purchaser does not obtain addenda. The purchaser is reminded that the changes to the Regulations can be found on the Federal Register's web site.

Participation by state and federal agency representative(s) or person(s) affiliated with industry is not to be interpreted as government or industry endorsement of the guide material in this Guide.

Conversions of figures to electronic format courtesy of ViaData Incorporated.

Cover photos of meters and pipeline with gauge provided by permission of Spire Inc. (formerly Laclede Gas Company); cover photo of welder provided by permission of the Southern California Gas Company.

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Engineers (ASME), the ASME initiated discussions with the DOT/OPS, in an effort to establish the future role of the B31.8 Code Committee with respect to pipeline safety. As a result of those discussions, the ASME decided to form the ASME Gas Piping Standards Committee. The title of the Committee was changed to the Gas Piping Technology Committee (GPTC) on September 20, 1982.

The first edition of the "Guide for Gas Transmission and Distribution Piping Systems" was published on December 15, 1970. It was essentially a compilation of the Federal Safety Standards and the then current ANSI B31.8 Code material that was relevant to the Part 192 requirements. Subsequent editions and addenda to the "Guide" had "how to" Guide Material directly following each of the standards of 49 CFR Part 192, and numerous guide appendices. Part 191 was subsequently added to the 1995 Edition of the Guide.

On October 18, 1989, the GPTC voted to transfer its affiliation from ASME to the American Gas Association (AGA). The transfer of copyright for the Guide from ASME to AGA was effective on April 10, 1990 and the AGA was designated the committee Secretariat. The first edition of the Guide published by AGA, as the new copyright holder/Secretariat, was in November 1990 and was designated the 1990-91 Edition. The GPTC sought ANSI approval of their procedures and was approved as an Accredited Standards Committee GPTC Z380 on January 30, 1992. The 1990 Edition of the Guide was approved as ANSI GPTC Z380.1 on December 2, 1992.

The current 2022 Edition supersedes all previous editions and respective addenda as follows: *Guide for Gas Transmission and Distribution Piping Systems* 1970, 1973, 1976, 1980, 1983, 1986 and then ANSI/GPTC Z380.1-1990, *Guide for Gas Transmission and Distribution Piping Systems*, followed by 1995, 1998, 2003, 2009, and 2012. The title of the Guide was revised for the 2015 Edition to "Guide for Gas Transmission, Distribution, and Gathering Piping Systems."

FOREWORD

The primary purpose of GPTC Z380.1 "Guide for Gas Transmission, Distribution, and Gathering Piping Systems" (Guide) is to provide assistance to the operator in complying with the intent of the Code of Federal Regulations (CFR) in the performance requirements contained in the Transportation of Natural and Other Gas by Pipelines, Title 49 Subchapter D-Pipeline Safety: Part 191 - Annual Reports, Incident Reports, and Safety-Related Condition Reports; and Part 192 - Minimum Federal Safety Standards (typically referred to hereinafter as the "Regulations").

The Guide includes the Minimum Federal Safety Standards together with the design recommendations, material reference, and recommended practices of the GPTC. The function of the GPTC's guide material is to provide "how to" supplementary recommendations related to the Minimum Federal Safety Standards. The Committee continuously works to pinpoint areas where more guide material could be provided in support of the Minimum Federal Safety Standards and related Regulations.

The Guide includes the Federal Regulations plus the GPTC's guide material for both Parts 191 and 192. The Guide is published in loose-leaf and electronic formats. As changes occur to the Regulations and related guide material, addenda are formatted to enable the replacement of pages in your *Guide* with updated pages. Addenda are available for free downloading from the GPTC webpage at www.aga.org/gptc or paper copies may be purchased at https://www.aga.org/aga-publications for a nominal fee. A new edition, incorporating all previous addenda that have been published, is usually issued every three years.

The historical reconstruction of the Regulations is available in AGA X69804, "Historical Collection of Natural Gas Pipeline Safety Regulations." It includes the original version of Parts 191 and 192 and all their amendments through Amdts. 191-15 and 192-93 (published September 15, 2003). The Federal Register preamble to the amendments is included as well. This collection of all earlier amendments has been established as a readily accessible reference to supplement the Guide or to aid research activity. However, considering the electronic availability of amendments starting in 2004, refer to the Federal Register web site for later amendments.

The format of the Guide includes the title of each numbered section of the Regulations and is followed by the effective date of the latest amendment activity or effective date of the original version if no amendment has been issued. The Regulation is followed by a list of amendment or control numbers for the respective section and the applicable guide material as developed by the Committee.

The Guide is maintained using the continuous maintenance process. Proposals to revise any guide material may be submitted to the Committee at any time. A *Form for Proposals on ANSI GPTC Z380.1* is provided at the end of the Guide and may also be obtained on the GPTC website at www.aga.org/gptc. Use that form to describe and justify the proposal and submit it to: GPTC Secretary, American Gas Association, 400 N. Capitol Street, NW, Washington, D.C. 20001 (or email GPTC@aga.org). A separate completed form should be submitted for each proposed revision.

Requests for interpretations, proposed additions, and revisions to the Regulations should be directed to the Associate Administrator for Pipeline Safety, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, East Building, 2nd Floor, 1200 New Jersey Avenue, SE, Washington, D.C. 20590-0001.

(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. State reporting obligations might differ from federal requirements and might require operators to report incidents not meeting the federal definition of an incident. States might also have shorter timeframes for reporting incidents than the timeframes in §191.5. The operator should consider providing (even if not required) the appropriate state agency with the same documents and reports that are provided to PHMSA.

(h) 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.

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

(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.

§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

(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

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 or connected series of pipelines, other than a gathering line, that:**

(1) Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center;

(2) Has an MAOP of 20 percent or more of SMYS;

(3) Transports gas within a storage field; or

(4) Is voluntarily designated by the operator as a transmission pipeline.

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.**

***Wrinkle bend* means a bend in the pipe that:**

(1) Was formed in the field during construction such that the inside radius of the bend has one or more ripples with:

(i) An amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple; or

(ii) With ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.

(2) (i) If the length of the wrinkle bend cannot be reliably determined, then w *rinkle bend* means a bend in the pipe where (h/D)*100 exceeds 2 when S is less than 37,000 psi (255 MPa), where (h/D)*100 exceeds (47000— *S*)/10,000 +1 for psi [324— *S*)/69 +1 for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where (h/D)*100 exceeds 1 when S is 47,000 psi (324 MPa) or more.

(ii) Where:

(A) D = Outside diameter of the pipe, in. (mm);

(B) h = Crest-to-trough height of the ripple, in. (mm); and
(C) S = Maximum operating hoop stress, psi (S/145, MPa).

[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, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022, with Correction 87 FR 64384, October 25, 2022]

GUIDE MATERIAL

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, *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.

GLOSSARY OF COMMONLY USED ABBREVIATIONS

Note: For added organizational abbreviations, see Guide Material Appendix G-192-1, Sections 4 and 5.

Abbreviation	Meaning
ABS	acrylonitrile-butadiene-styrene
ACVG	alternating current voltage gradient
AOC	abnormal operating condition
ASV	automatic shut-off valve
BAP	baseline assessment plan
CAB	cellulose acetate butyrate
CDA	confirmatory direct assessment
CGI	combustible gas indicator
CIS	close-interval survey
CP	cathodic protection
CTS	copper tube size
DA	direct assessment
DCVG	direct current voltage gradient
DIMP	Distribution Integrity Management Program
ECA	engineering critical assessment
ECDA	external corrosion direct assessment
EFV	excess flow valve
EFVB	excess flow valve – bypass (automatic reset)
EFVNB	excess flow valve – non-bypass (manual reset)
ERW	electric resistance welded
ESD	emergency shutdown
FAQ	frequently asked question
FBE	fusion bonded epoxy
FRP	fiberglass reinforced plastic
GIS	geographic information system
GMA	Guide Material Appendix
GPS	global positioning system
H_2S	hydrogen sulfide
HCA	high consequence area
HDB	hydrostatic design basis
HFI	hydrogen flame ionization

GLOSSARY OF COMMONLY USED ABBREVIATIONS (Continued)	
Abbreviation	**Meaning**
IBR	Incorporated by reference (see §192.7)
IC	internal corrosion
ICDA	internal corrosion direct assessment
ICS	Incident Command System
ILI	in-line inspection
IMP	integrity management program
IPS	iron pipe size
IR drop	voltage drop
LEL	lower explosive limit
LNG	liquefied natural gas
LPG	liquid or liquefied petroleum gas
LTHS	long-term hydrostatic strength
MAOP	maximum allowable operating pressure
MIC	microbiologically influenced corrosion
MOC	management of change
MOP	maximum operating pressure
MRS	minimum required strength
NAPSR	National Association of Pipeline Safety Representatives
NDE	nondestructive evaluation
NPS	nominal pipe size
O_2	oxygen
O&M	operations and maintenance
OCS	outer continental shelf
OQ	operator qualification
PA	polyamide
P&M measures	preventive and mitigative measures
PDB	pressure design basis
PE	polyethylene
PFP	predicted failure pressure
PIC	potential impact circle
PIR	potential impact radius
PVC	poly (vinyl chloride), also written as polyvinyl chloride
RCV	remote control valve
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
SCCDA	stress corrosion cracking direct assessment
SCFH	standard cubic feet per hour
SDB	strength design basis
SDR	standard dimension ratio
SME	subject matter expert
SMYS	specified minimum yield strength
TVC	traceable, verifiable, and complete
USGS	United States Geological Survey
USCG	United States Coast Guard

TABLE 192.3i

§192.5

Class locations.

[Effective Date: 07/01/2020]

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

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

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

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

(1) A Class 1 location is:
(i) An offshore area; or
(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

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

(3) A Class 3 location is:

(i) Any class location unit that has 46 or more buildings intended for human occupancy; or
(ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.
(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:
(1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.
(2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.
(d) An operator must have records that document the current class location of each pipeline segment and that demonstrate how the operator determined each current class location in accordance with this section.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-56, 52 FR 32924, Sept. 1, 1987; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996 and Amdt. 192-78 Correction, 61 FR 35139, July 5, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt 192-125, Oct. 1, 2019]

GUIDE MATERIAL

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

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).

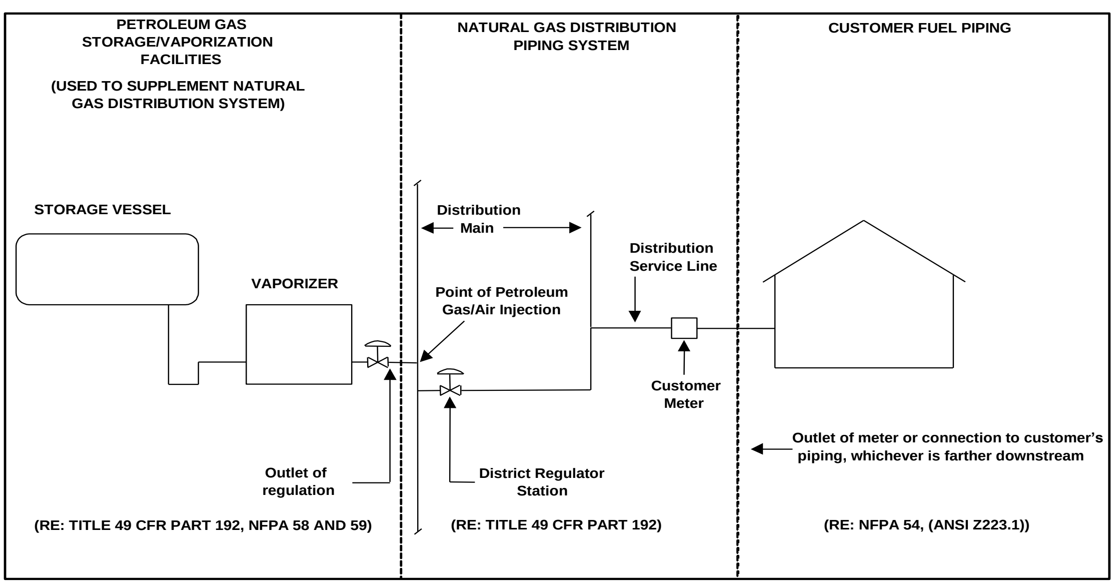

FIGURE 192.11A

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

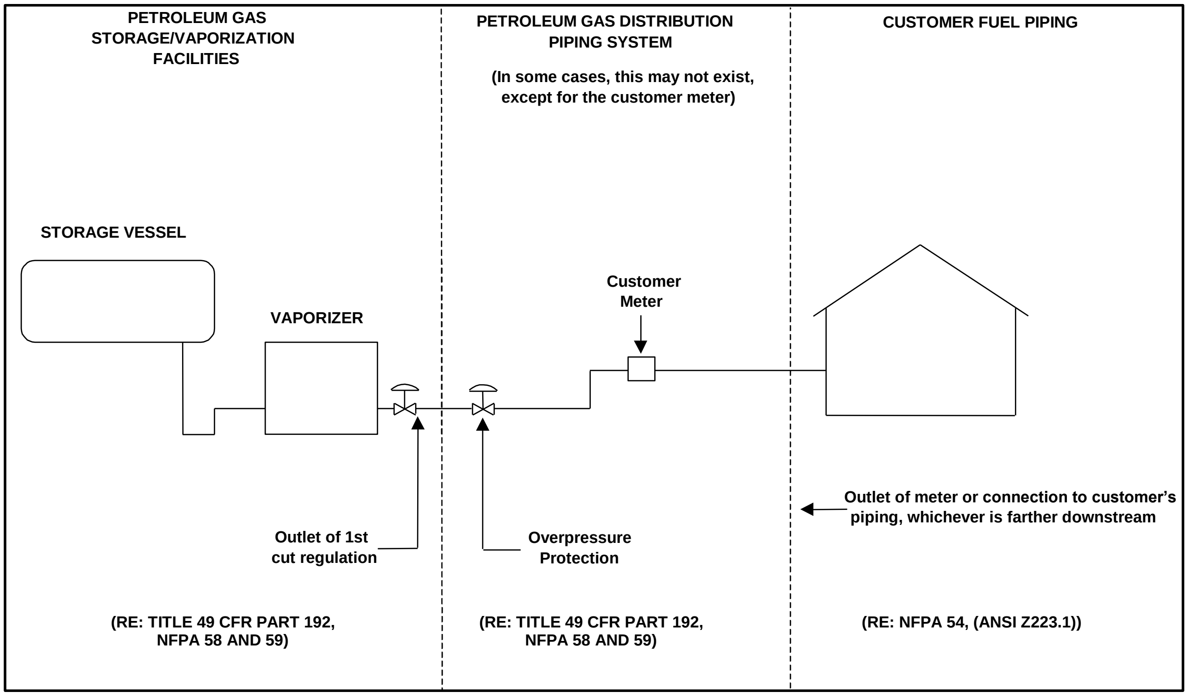

FIGURE 192.11B

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) Utility Gas Plant.

(i) A plant that stores and vaporizes LP-Gas for distribution that supplies either LP Gas or LP-Gas gas/air mixtures to a gas distribution system of 10 or more customers and is covered by NFPA 59.

(ii) All other plant and storage installations should comply with NFPA 58.

(iii) Jurisdiction under Part 192 is determined by §192.1(b)(5).

(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

§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

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.

(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 necessary.

§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

(a) Records for pipeline components installed in steel transmission and Type A gathering lines should be traceable, verifiable, and complete to establish or confirm the MAOPs. The records requirements of §192.205 are not applicable for Type B or C gathering lines (§192.9).

(b) Records may include the following.

- (1) Mill test reports, which might have the following data.
  - (i) Heat numbers.
  - (ii) Steel chemistry.
  - (iii) Yield strength.
  - (iv) Ultimate tensile strength.
  - (v) Pipe grade.
  - (vi) Pipe wall thickness
  - (vii) Manufacturing process.
- (2) Purchase requisitions and orders.

(3) Bills of lading.
(4) Pressure test records and test procedure documentation.
(5) Pressure rating documentation.
(6) Manufacturing standard(s) documentation.
(7) Manufacturing inspection records.
(8) Coating documentation.
(9) GPS or survey coordinates for the location of installed components.
(10) Construction inspection notes and photographs related to field installation of pipeline components.

(c) Records may be maintained at a central location or at multiple locations for the operational life of the components.

(d) Records may be maintained as paper copies, electronically, or in any other appropriate format.

(b) Information on preheating and stress relieving of welded connections can be found in the above references. Preheating and stress relieving should be performed in accordance with the qualified welding procedure being used.

§192.227
Qualification of welders.

[Effective Date: 07/01/2020]

(a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, *see* §192.7), or section IX of the ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, *see* §192.7). However, a welder or welding operator qualified under an earlier edition than the edition listed in §192.7 of this part may weld but may not requalify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

(c) For steel transmission pipe installed after July 1, 2021, records demonstrating each individual welder qualification at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

[Amdt. 192-18, 40 FR 10181, Mar. 5, 1975 with Amdt. 192-18A, 40 FR 27222, June 27, 1975; Amdt. 192-22, 41 FR 13589, Mar. 31, 1976; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-52, 51 FR 20294, June 4, 1986; 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. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-103, 72 FR 4655, Feb. 1, 2007; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015; Amdt. 192-123, 82 FR 7997, Jan. 23, 2017; Amdt. 192-125, Oct. 1, 2019]

GUIDE MATERIAL

(1) It is the operator's responsibility to ensure that all welding is performed by qualified welders and welding operators.

(2) The ability of welders and welding operators to make sound welds should be determined by test welds using previously qualified welding procedures. The evaluation of test welds may be conducted by qualified operator personnel or testing laboratories.

(3) For steel transmission, offshore and onshore Type A gathering pipe installed after July 1, 2021, records of the qualification of each individual welder should include the following.
   (a) Welder’s identity.
   (b) Welding procedure to which the welder is qualified.

(4) The operator should consider identifying the specific welds produced by each individual welder and the locations of those welds in the construction records using methods such as the following.

(a) Measurements from known landmarks.
(b) GPS coordinates.
(c) Station number.
(d) Other methods.

§192.229

Limitations on welders and welding operators.

[Effective Date: 03/12/21]

(a) No welder or welding operator whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(b) A welder or welding operator may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder or welding operator was engaged in welding with that process. Alternatively, welders or welding operators may demonstrate they have engaged in a specific welding process if they have performed a weld with that process that was tested and found acceptable under section 6, 9, 12, or Appendix A of API Std 1104 (incorporated by reference, see § 192.7) within the preceding 71⁄2 months.

(c) A welder or welding operator qualified under §192.227(a)—

(1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder or welding operator has had one weld tested and found acceptable under either section 6, section 9, section 12 or Appendix A of API Std 1104 (incorporated by reference, *see* §192.7). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 71⁄2 months. A welder or welding operator qualified under an earlier edition of a standard listed in §192.7 of this part may weld, but may not re-qualify under that earlier edition; and,

(2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder or welding operator is tested in accordance with paragraph (c)(1) of this section or re-qualifies under paragraph (d)(1) or (d)(2) of this section.

(d) A welder or welding operator qualified under §192.227(b) may not weld unless—

(1) Within the preceding 15 calendar months, but at least once each calendar year, the welder or welding operator has re-qualified under §192.227(b); or

(2) Within the preceding 71⁄2 calendar months, but at least twice each calendar year, the welder or welding operator has had—

(i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(ii) For a welder who works only on service lines 2 inches (51 millimeters) or smaller in diameter, the welder has had two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

[Amdt. 192-18, 40 FR 10181, Mar. 5, 1975 with Amdt. 192-18A, 40 FR 27222, June 27, 1975; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; 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; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

A welding "process" is one element of a welding "procedure." Processes commonly used in pipeline welding procedures include the following:

(a) Shielded metal arc.
(b) Submerged arc.
(c) Gas tungsten arc

(d) Gas metal arc.
(e) Flux-cored arc.
(f) Oxyacetylene.

§192.231
Protection from weather.
[Effective Date: 11/12/70]

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

GUIDE MATERIAL

No guide material necessary.

§192.233
Miter joints.
[Effective Date: 11/12/70]

(a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3 degrees.
(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 12½ degrees and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.
(c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90 degrees.

GUIDE MATERIAL

No guide material necessary.

§192.235
Preparation for welding.
[Effective Date: 11/12/70]

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

GUIDE MATERIAL

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

For distribution line construction or repairs: 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]

1.3 *Inspections*.

(a) Onshore.

(1) The condition of the ditch bottom should be inspected just before the pipe is lowered-in.

(2) The surface of the coated pipe should be inspected as the pipe is lowered into the ditch. Coating lacerations indicate that the pipe may have been damaged after the coating was applied.

(3) The fit of the pipe to the ditch should be inspected before backfilling.

(b) Offshore.

(1) The surface of the corrosion preventive coating should be inspected before weight-coating.

(2) The weight-coating should be inspected before the pipe is welded.

2 JOINT RESTRAINT

2.1 *Harnessing or buttressing*.

Suitable harnessing or buttressing should be provided at points where the pipe deviates from a straight line and the thrust, if not restrained, would separate the joints.

2.2 *Special considerations*.

Cast iron pipe installed in unstable soils should be provided with suitable supports. See Guide Material Appendix G-192-18.

3 BACKFILLING

3.1 *General*.

Backfilling should be performed in a manner to provide firm support under the pipe.

3.2 *Backfill material*.

(a) General. If there are large rocks in the material to be used for backfill, care should be used to prevent damage to the coating. This may be accomplished by the use of abrasion protection material (e.g., rock shield) or by making an initial fill with enough rock-free material to prevent damage.

(b) Effects on cathodic protection (CP) system. Consideration should be given to the possible CP current shielding effects that may occur from the installation of non-conductive materials, such as abrasion protection.

3.3 *Abrasion Protection*.

Where an abrasion protection material is used to prevent coating damage, it must be installed properly. One method of installing a wrap-type material is to secure it entirely around the pipe using fiberglass tape or other suitable banding material. The material should not be draped over the pipe unless suitable backfill and padding is placed in the ditch to provide continuous and adequate support of the pipe in the trench.

3.4 *Consolidation*.

If trench flooding is used to consolidate the backfill, care should be taken to see that the pipe is not floated from its firm bearing on the trench bottom. Where mains are installed in existing or proposed roadways or in unstable soil, flooding should be augmented by wheel rolling or mechanical compaction. Multi-lift mechanical compaction can be used in lieu of flooding.

3.5 *Warning tape.*

(a) After the pipe is installed in the ditch and backfilling has begun, consider placing a highly visible warning tape over the pipe to indicate the presence of a pipeline so that the warning tape is encountered first if someone excavates in the vicinity. The tape should be centered over the pipe for its entire length.

(b) The tape should be yellow to signify gas.

(c) A safety warning or message, such as “Warning: Buried Gas Pipeline”, should be imprinted on the tape.

(d) An operator should consider using warning tape for new installations and anytime existing pipe is exposed.

(e) When an operator is installing multiple pipelines within the same right-of-way, the same decision should be made on using warning tape for each of the newly installed pipelines.

4 DAMAGE PREVENTION

(a) Consider temporarily marking facilities during installation with paint, flags, or other means to help prevent damage in areas where continued construction is expected. This includes pipelines that are not energized.
(b) Check for and remove previous markings that might confuse others working around the facilities.

5 ALTERNATIVE INSTALLATION METHODS

5.1 Horizontal directional drilling.
(a) For damage prevention considerations while performing directional drilling or using other trenchless technologies, see Guide Material Appendix G-192-6.
(b) For additional considerations for horizontal directional drilling to install steel pipelines or plastic pipelines, see Guide Material Appendices G-192-15A and G-192-15B, respectively.

§192.321

Installation of plastic pipe.

[Effective Date: 01/22/19]

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

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

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

(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

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

(g) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

(1) The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

(2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

(3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

(h) Plastic pipe may be installed on bridges provided that it is:

(1) Installed with protection from mechanical damage, such as installation in a metallic casing;

(2) Protected from ultraviolet radiation; and

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

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

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

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

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

[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. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-94, 69 FR 32886, June 14, 2004; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

1 GENERAL PRECAUTIONS

1.1 Handling.

For guidance to protect pipe during handling, see guide material under §192.69

1.2 Considerations to minimize damage by outside forces.

See Guide Material Appendix G-192-13.

2 DIRECT BURIAL OF PLASTIC PIPE

2.1 *Contraction*.
The piping should be installed with sufficient slack to provide for possible contraction. Under high temperature conditions, cooling may be necessary before the last connection is made. See 3.5(f) of the guide material under §192.281.

2.2 *Installation stress*.
When long sections of piping that have been assembled alongside the ditch are lowered-in, care should be taken to avoid any strains that may overstress or buckle the piping, or impose excessive stress on the joints.

2.3 *Backfilling*.
(a) General. Blocking should not be used to support plastic pipe. Plastic pipe should be laid on undisturbed soil, well-compacted soil, well-tamped soil, or other continuous support. If plastic pipe is to be laid in soils that may damage it, the pipe should be protected by suitable rock-free materials.
(b) Backfill material. Backfilling should be performed in a manner to provide firm support around the piping and to protect the piping from damage. Plastic piping materials could be affected by rock impingement. The backfill expected to come in direct contact with the pipe should be free of rocks, pieces of pavement, or other materials that might damage the pipe. Rocks or similar material can cause stress concentrations that could limit the long-term performance of the piping system should pipe contact occur.
(1) Consult the pipe manufacturer for guidance to determine the appropriate backfill for its plastic piping material.
(2) Maximum particle size for materials within 6 inches of the pipe, including bedding materials and other initial materials that might damage the pipe, are shown in Table 192.321i.

Pipe Size	Maximum Particle Size (inch)
NPS 4 and smaller	1/2
NPS 6 and NPS 8	3/4
Larger than NPS 8	1

TABLE 192.321i

(3) Beyond the 6-inch zone, the final backfill should be free of materials that might damage the pipe, such as rocks (3 inches or larger), pieces of pavement, or construction debris. Additional guidance on backfill is provided in ASTM D2774, "Standard Practice for Underground Installation of Thermoplastic Pressure Piping."
(c) Consolidation. If trench flooding is used to consolidate the backfill, care should be taken to see that the piping is not floated from its firm bearing on the trench bottom. Where mains and service lines are installed in existing or proposed roadways or in unstable soil, flooding should be augmented by wheel rolling or mechanical compaction. Multi-lift mechanical compaction can be used in lieu of

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. 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:

(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

(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 §192.121.

(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.

§192.383

Excess flow valve installation.

[Effective Date: 04/14/17]

(a) Definitions. As used in this section:

Branched service line **means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.**

Replaced service line **means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.**

Service line serving single-family residence **means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence (SFR).**

(b) ***Installation required.*** **An EFV installation must comply with the performance standards in §192.381. After April 14, 2017 each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated:**

(1) A single service to one SFR;

(2) A branched service line to a SFR installed concurrently with a primary SFR service line (i.e., a single EFV may be installed to protect both service lines);

(3) A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV;

(4) Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation, based on installed meter capacity, and

(5) A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity.

(c) ***Exceptions to excess flow valve installation requirement.***

(1) The service line does not operate at a pressure of 10 psig or greater throughout the year;

(2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a customer;

(3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

(4) An EFV meeting performance standards in §192.381 is not commercially available to the operator.

(d) Customer's right to request an EFV.

Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one of the exceptions in paragraph (c) of this section may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.

(e) ***Operator notification of customers concerning EFV installation.***

Operators must notify customers of their right to request an EFV in the following manner:

(1) Except as specified in paragraphs (c) and (e)(5) of this section, each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, Web site postings, and e-billing notices.

(2) The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks.

(3) The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known.

(4) The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of paragraph (c) are not present, the operator must install an EFV at a mutually agreeable date.

(5) Operators of master-meter systems and liquefied petroleum gas (LPG) operators with fewer than 100 customers may continuously post a general notification in a prominent location frequented by customers.

(f) *Operator evidence of customer notification.*

An operator must make a copy of the notice or notices currently in use available during PHMSA inspections or State inspections conducted under a pipeline safety program certified or approved by PHMSA under 49 U.S.C. 60105 or 60106.

(g) *Reporting.* Except for operators of master-meter systems and LPG operators with fewer than 100 customers, each operator must report the EFV measures detailed in the annual report required by §191.11.

[Issued by Amdt. 192-83, 63 FR 5464, Feb. 3, 1998 with Amdt. 192-83 Correction, 63 FR 20134, Apr. 23, 1998; Amdt. 192-113, 74 FR 63906, Dec. 4, 2009 with Amdt. 192-113 Correction, 75 FR 5244, Feb. 2, 2010; Amdt. 192-116, 76 FR 5494, Feb. 1, 2011; Amdt. 192-121, 81 FR 70987 Oct. 14, 2016 with Amdt. 192-121 Correction, 81 FR 72739, Oct. 21, 2016]

GUIDE MATERIAL

1 EXCESS FLOW VALVES (EFV) INSTALLATIONS

1.1 General.

Unless one or more of four conditions listed in §192.383(c) is present (service line does not operate at a pressure of at least 10 psig throughout the year, contaminants in the gas stream could interfere with the EFV's operation or cause loss of service to the customer, EFV could interfere with required operation or maintenance activities such as blowing liquids from the line, or an EFV is not commercially available for the application), §192.383 requires an EFV to be installed at the time of installation of new or replaced service lines that serve the following.

(a) A single-family residence.
(b) A single-family residence on a branched service line that is installed concurrently with the primary single-family residence service line. A single EFV may be installed to protect both the primary and the branched service lines.
(c) A single-family residence, that is branched from an existing service line that does not have an EFV.
(d) A multi-family residence with a total meter capacity not exceeding 1,000 SCFH for the service line.
(e) A single, small commercial customer with meter capacity not exceeding 1,000 SCFH.

1.2 Service line supplying a single-family residence.

As required by §192.383(b)(1) and except for the limitations of §192.383(c), an operator must install an EFV on a new or replaced service line to a single-family residence. The following illustrations (Figures 192.383A and 192.383B) show where an EFV should normally be installed on a service line to a single-family residence to comply with §192.381(d). For other EFV installation considerations, see guide material under §192.381.

EFV with Meter Located at Residence

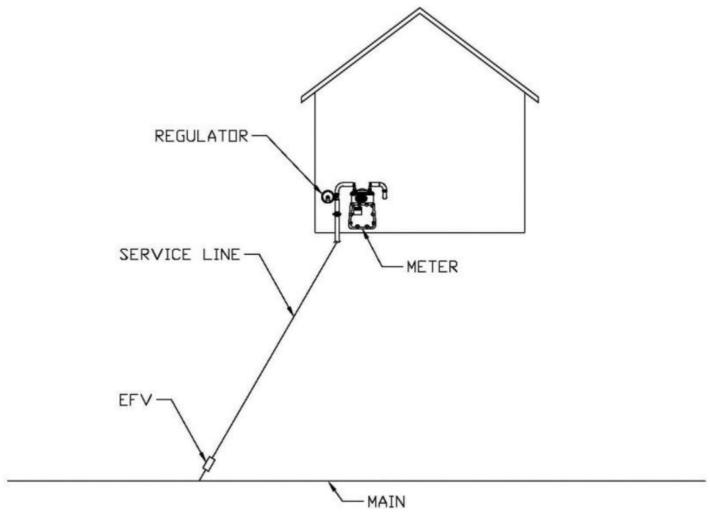

FIGURE 192.383A

EFV with Meter Located in the Vicinity of the Main

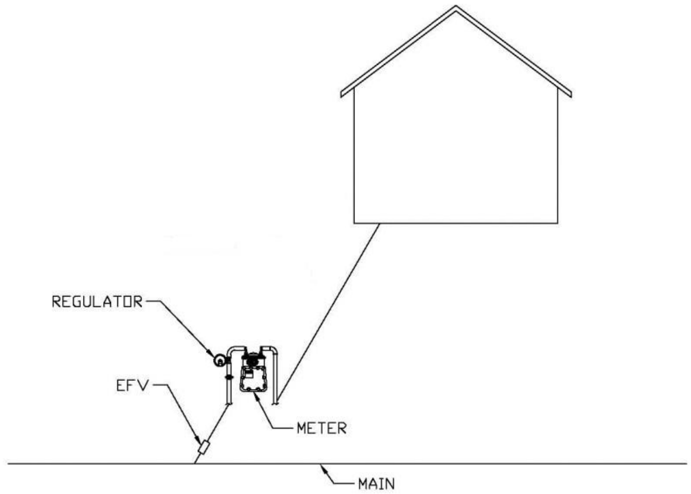

FIGURE 192.383B

1.3 Service line supplying adjacent single-family residences.

As required by §192.383(b)(2) and (3) and except for the limitations of §192.383(c), an operator must install an EFV on a new or replaced branch service line to adjacent single-family residences. Examples of a service line to adjacent single-family residences are illustrated in Figures 192.383C and 192.383D.

EFV for New or Replaced Service Line Serving Two Single-Family Residences with One EFV

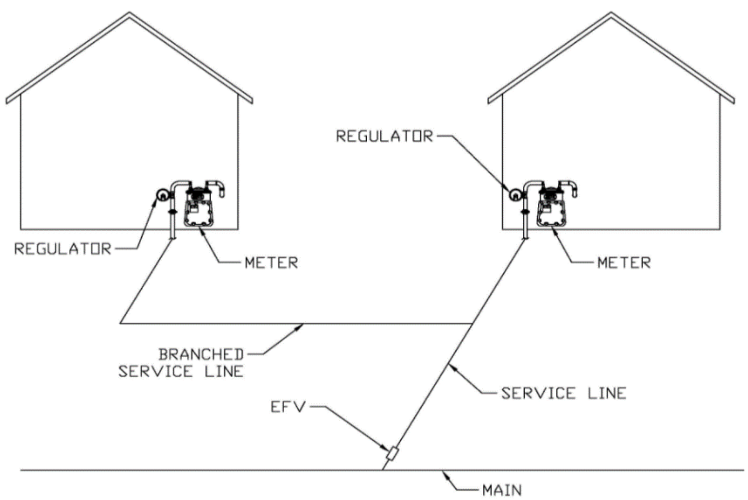

FIGURE 192.383C

Note: The branched service line may be installed at the same time as the original service line or it may be installed afterwards.

EFV for New or Replaced Branched Service on an Existing Single-Family Residence Service Line that Does Not Have an EFV

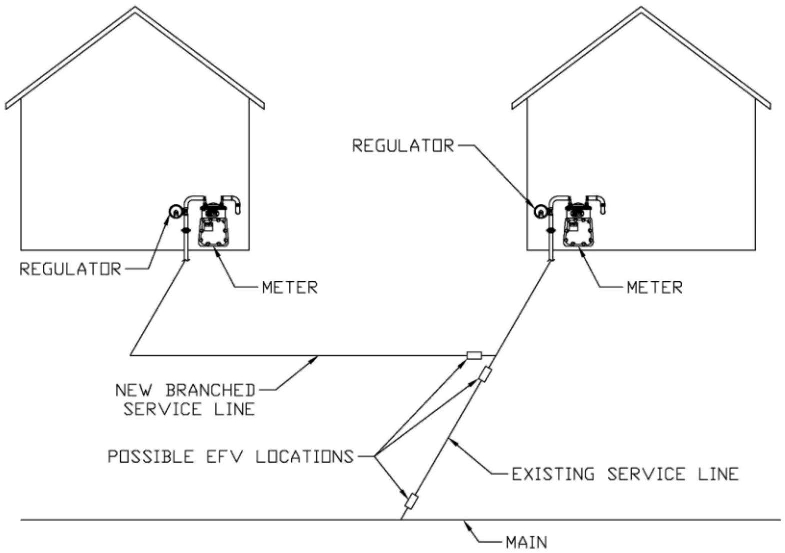

FIGURE 192.383D

Note: If a new or replaced branch service is installed from an existing service line that does not have an EFV, then the EFV may be placed in one of three possible locations as shown in the figure above.

1.4 Service line supplying a multi-family residence.

As required by §192.383(b)(4) and except for the limitations of §192.383(c), an operator must install an EFV on a service line to multi-family residences with a total meter capacity for the service line not exceeding 1,000 SCFH at the time of installation (Figure 192.383E).

EFV for Multi-Family Residence Where Total Meter Capacity for the Service Line Does Not Exceed 1,000 SCFH

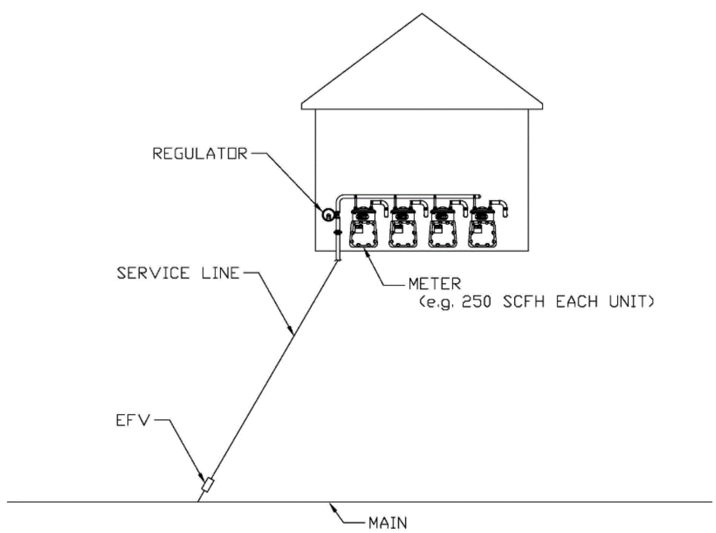

FIGURE 192.383E

1.5 Service line supplying a small commercial customer.

As required by §192.383(b)(5) and except for the limitations of §192.383(c), an operator must install an EFV on a service line to a small commercial customer with a meter capacity not exceeding 1,000 SCFH at the time of installation (Figure 192.383F).

EFV for Small Commercial Customer

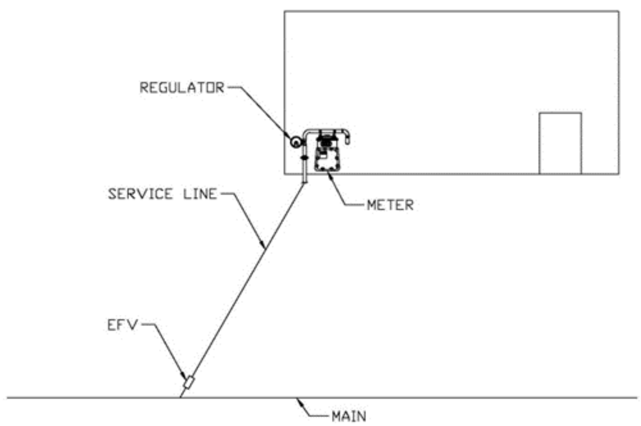

FIGURE 192.383F

§192.385
Manual service line shut-off valve installation.

[Effective Date: 04/14/17]

(a) Definitions. As used in this section:

Manual service line shut-off valve **means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.**

(b) *Installation requirement.* The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH.

(c) *Accessibility and maintenance.* Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this section are subject to regular scheduled maintenance, as documented by the operator and consistent with the valve manufacturer's specification.

[Issued by Amdt. 192-121, 81 FR 70987, Oct. 14, 2016]

GUIDE MATERIAL

1 MANUAL SERVICE LINE SHUT-OFF VALVE INSTALLATION

1.1 General.

The following guide material describes the installation and maintenance of a manual service line shut-off valve (e.g., curb valve) required under §192.385. The purpose of this valve is to enable operators, or other personnel authorized by the operator, to manually shut off gas flow to the service line, if needed. The manual service line shut-off valve described in this section does not refer to the riser valve or the meter shut-off valve at the meter set assembly located at the building where the service line terminates.

1.2 Installation.

Section 192.385 requires an operator to install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacities exceeding 1,000 SCFH. A manual service line shut-off valve should be located near the service main or a common source of supply to protect as much of the service line as is practicable.

Notes:

(1) The installation of a manual service line shut-off valve on a service line to single family residence (SFR) or branched service line to an SFR, regardless of installed meter capacity, does not satisfy the requirement to install an EFV under §192.383.

(2) The exceptions listed under §192.383(c) for the installation of an EFV do not apply to a manual service line shut-off valve.

1.3 Accessibility and Maintenance

A manual service line shut-off valve (e.g., curb valve) installed in accordance §192.385 must be installed in such a manner that it will be accessible in an emergency. This valve is subject to regularly scheduled maintenance consistent with the valve manufacturer’s specification (or as specified by the operator if the manufacturer provides no specification), and the valve is to be accessible and operable. This maintenance may occur in conjunction with other activities when qualified personnel are present (e.g., meter-change programs, patrolling, leak surveys, activities where the service would be shut off). These valve maintenance requirements do not apply to valves that are installed in addition to an EFV.

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(b) An evaluation of the pipe condition.
(c) The extent of the initial investigation.
(d) The extent of any additional investigation conducted, if remedial action is required.

3 ADJACENT UNDERGROUND STRUCTURES

3.1 General.

When inspecting the exposed pipeline, consideration should be given to the proximity and condition of existing conduits, ducts, sewer lines and similar structures, including abandoned facilities, which might have the potential to provide a path for the migration of leaking gas.

3.2 Cathodic shielding.

Visual inspection for corrosion is an effective method to determine cathodic shielding of a pipeline. The area exposed around a pipeline should be inspected for foreign objects that can contribute to cathodic shielding. Once a corroded or shielded area is discovered, remedial measures should be taken. See 9.2 of the guide material under §192.465 for further information regarding shielding of current.

4 INSPECTING PIPELINE IN CASINGS

4.1 Visual inspection.

Normally, it is impractical to inspect a carrier pipe in a casing. Whenever the encased carrier pipe is exposed, it should be visually inspected. Visual inspection of the encased carrier pipe for atmospheric corrosion conditions within casings should be made in those situations where the casing must be lengthened due to road widening or other construction, and where the carrier pipe must be pulled out of the casing and replaced.

4.2 In-line inspection (ILI).

ILI surveys may be used to evaluate corrosion of an encased carrier pipe. However, it is normally not practical to use this technique except when it is part of a general ILI survey.

5 INTEGRITY MANAGEMENT CONSIDERATIONS

The examination of exposed buried pipelines might provide additional opportunities for acquiring data to include in the threat and risk analysis required by an integrity management program, such as §§192.917 and 192.1007. An operator should review the data collection and integration processes associated with its integrity management plan to determine if additional data collection is beneficial. Procedures and forms may need to be modified to include additional data collection. Data collected should be made available to integrity management personnel.

§192.461

External corrosion control: Protective coating.

[Effective Date: 05/24/23]

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must —

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling (including, but not limited to, transportation, installation, boring, and backfilling) and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

(f) Promptly after the backfill of an onshore steel transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), but no later than 6 months after the backfill, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

(g) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (f) of this section.

(h) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

(i) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (f) through (h) of this section.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

1 GENERAL

Each operator should specify protective coatings for factory-applied and field-applied coatings to meet the requirements stated in §192.461. Materials purchased with factory-applied coatings should include references to the appropriate industry standard for the coating selected with options such as platings and overlays clearly indicated. Field-applied coating requirements should state the expectation to follow manufacturer application instructions including appropriate surface preparation.

2 FACTORY APPLIED COATINGS

When purchasing materials with factory-applied coatings, operators should ensure coating materials selected and the application processes will be appropriate for the service conditions (e.g., below ground, above ground) and method of installation. For horizontal directional drilling (HDD) installations, see Guide Material Appendix G-192-15A, Section 5.3. Designation of the coating requirements could be an operator-developed material purchase specification for certain items (example 1) or just review and acceptance of manufacturer coating processes (example 2).

(a) Example 1:
A steel line pipe coating specification for fusion bonded epoxy may refer to NACE SP0394 (see 7 below) and add requirements such as the following.

(1) Approved coating type and manufacturer of the Fusion Bonded Epoxy and Abrasion Resistant Overlay.
(2) Frequency of soluble salt testing.
(3) Coating thickness (i.e., minimum, maximum, average).
(4) Allowance of recycled materials.
(5) Production inspection above and beyond industry specification.
(6) Allowable holiday repairs.

(b) Example 2:
Manufacturers of risers, transition fittings, valves, and meter assemblies typically have standard coating materials and application processes for their product. Operators should review the manufacturer coating information, determine the appropriateness for the intended application, and document the acceptance. Considerations in the review process might include the following.
(1) ASTM B117 salt spray test results.
(2) Ensuring product free of water, dust, dirt, oil, or grease prior to coating.
(3) Surface preparation procedures.
(4) Coating material accommodating of all surfaces without cracking, disbonding, or flaking.
(5) Coating options such as:
(i) 2-part epoxy primer and enamel overlay,
(ii) 2-part epoxy primer and 2-part urethane overlay, or
(iii) Zinc plating, 2-part epoxy primer, and 2-part urethane overlay.

3 FIELD-APPLIED COATINGS

(a) There are numerous situations where field application of coatings is required during new pipeline installation, maintenance, and repair activities. Examples include weld joints, service tees, buried valves, thermowelds, and meter assembly maintenance. Compatibility of field-applied coatings with the associated factory-applied coatings should be a consideration in the selection. Due to the variables in the field compared to factory conditions, minimizing the amount of field applications is generally preferred.
(b) Typical field-applied coatings for the applications stated above include liquid epoxy, cold applied tape, hot applied tape, mastic, wax wrap, and shrink sleeves. Operators should specify the appropriate field applied coating for the conditions anticipated and provide manufacturer instructions for application.
(c) Surface preparation of the metallic surface is critical to achieve proper bonding with the coating material. Operators should specify expectations for surface preparation for the various situations that will typically be encountered.
(1) Bare steel should be free of water, dust, dirt, grease, oil, and other foreign matter.
(2) Welds should be free of slag, splatter, and scale.
(3) Sharp edges or burrs should be removed by filing or grinding.
(4) Blast cleaning, if required, should be to a NACE No. 2/SSPC-SP10 finish.
(5) Repair area should be dry and at a temperature at least 5 degrees above the dew point.
(6) Surfaces with oil, grease, pipe thread sealant, or other soluble surface contamination may be cleaned with an approved solvent provided it does not have a detrimental effect on the coating material.
(7) If primer is required, application details should be provided.

4 COATING INSPECTION

(a) The inspection of coatings is an important precautionary measure to ensure defects are identified prior to placing a facility in service. Operators should consider viable opportunities to validate coating integrity during coating application processes, following transportation and other logistical steps, during construction, and post-construction. Methods of inspection might include visual checks, thickness measurements where appropriate, electrical inspection for pipe (typically referred to as jeeping or holiday detection), and for significant facilities, post-construction indirect electrical measurement techniques (e.g., current drain tests, DCVG, close interval surveys).

(b) Operators should review manufacturer inspection requirements in the factory application processes. After delivery to warehouses or construction sites, inspect materials for visible damage.
(c) Inspect pipe coatings while pipe is being lowered into a trench by jeeping or holiday detection (see 4(d) below), and during backfill operations (see 3 of the guide material under §192.319). Pipe handling equipment such as rollers, slings, and chains should be selected and maintained to avoid potential coating damage during use. Backfilling operations should include procedures to ensure that materials contacting the pipe do not cause coating damage. Use of supplemental protection such as rockshield may also be considered.
(d) The holiday detection test is intended to detect voids, cracks, or contaminants in the coating that may lower the electrical resistance or dielectric strength of the coating. Operators should consider procedures specific to holiday detection that include the appropriate equipment to perform the test, voltage settings per coating type and thickness, requirements by pipe size, length and coating material, and pipe cleanliness expectations. The holiday detection test should be performed prior to lowering the pipe into the trench in order to identify any damage that may occur in the installation process. See NACE documents related to holiday detection in 7 below.
(e) Electrical measurements that can provide indications of coating integrity can be implemented as a further method of inspection. These techniques might require special resources so the operator should consider use of these for facilities deemed at special risk or for significant projects. Examples of these methods include current drain tests, DCVG, and close interval surveys.

5 ADVERSE DITCH CONDITIONS AND SUPPORT BLOCKS (§192.461(d))

(a) During pipe installation in ditch conditions that could cause coating damage or electrical shielding, preventative measures should be taken to protect the pipe and coating. Measures to consider include the following.
   (1) Grading ditch bottom to remove rocks or other foreign matter.
   (2) Use of bedding sand.
   (3) Screening of backfill to remove rocks or other detrimental debris.
   (4) Additional coating protection such as rockshield.
(b) Pipe supported over a trench should be placed on padded skids of sufficient size to safely support the pipe weight. If blocking is used to support valves or other assemblies, protective material that will not cause electrical shielding should be considered.

6 BORING OR DRIVING (§192.461(e))

See 2 of the guide material under §192.361.

7 REFERENCES

(a) ASTM B117, “Standard Practice for Operating Salt Spray (Fog) Apparatus” - (§192.461(a)(1)-(4)).
(b) NACE No. 2/SSPC-SP 10, “Near-White Metal Blast Cleaning” - (§192.461(a)(1)).
(c) Section 5 of NACE SP0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems” – (§192.461(a), (b), and (d)).
(d) NACE SP0188, “Discontinuity (Holiday) Testing of New Protective Coatings on Conductive Substrates” - (§192.461(c)).
(e) NACE SP0274, “High Voltage Inspection of Pipeline Coatings” - (§192.461(c)).
(f) Section 5 of NACE SP0375, “Field-Applied Underground Wax Coating Systems for Underground Metallic Pipes: Application, Performance, and Quality Control” - (§192.461(d)).
(g) NACE SP0394, “Application, Performance, and Quality Control of Plant-Applied Single Layer Fusion-Bonded Epoxy External Pipe Coating.”
(h) NACE SP0490, “Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coating of 250 to 760 μm (10 to 30 mil)” - (§192.461(c)).

§192.463

External corrosion control: Cathodic protection.

[Effective Date: 08/01/71]

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this subpart. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential —

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D of this part for amphoteric metals.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

[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 and remediation.

[Effective Date: 05/24/23]

(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 six times each calendar year, but with intervals not exceeding 2 ½ months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier.

(2) 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 must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (a) through (c) of this section. For onshore gas transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within one year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

(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.

(f) An operator must determine the extent of the area with inadequate cathodic protection for onshore gas transmission pipelines where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in appendix D to this part.

(1) Gas transmission pipeline operators must investigate and mitigate any non-systemic or location-specific causes.

(2) To address systemic causes, an operator must conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. An operator must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (d) of this section. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external 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; Amdt. 192-35, 44 FR 75384, Dec. 20, 1979 with Amdt. 192-35A, 45

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. See guide material under §192.227 for records demonstrating the qualification of each individual welder at the time of construction.

(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 and regulated gathering 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.

(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 https://www.aga.org/wp-content/uploads/2022/12/gptctechpaper.pdf.

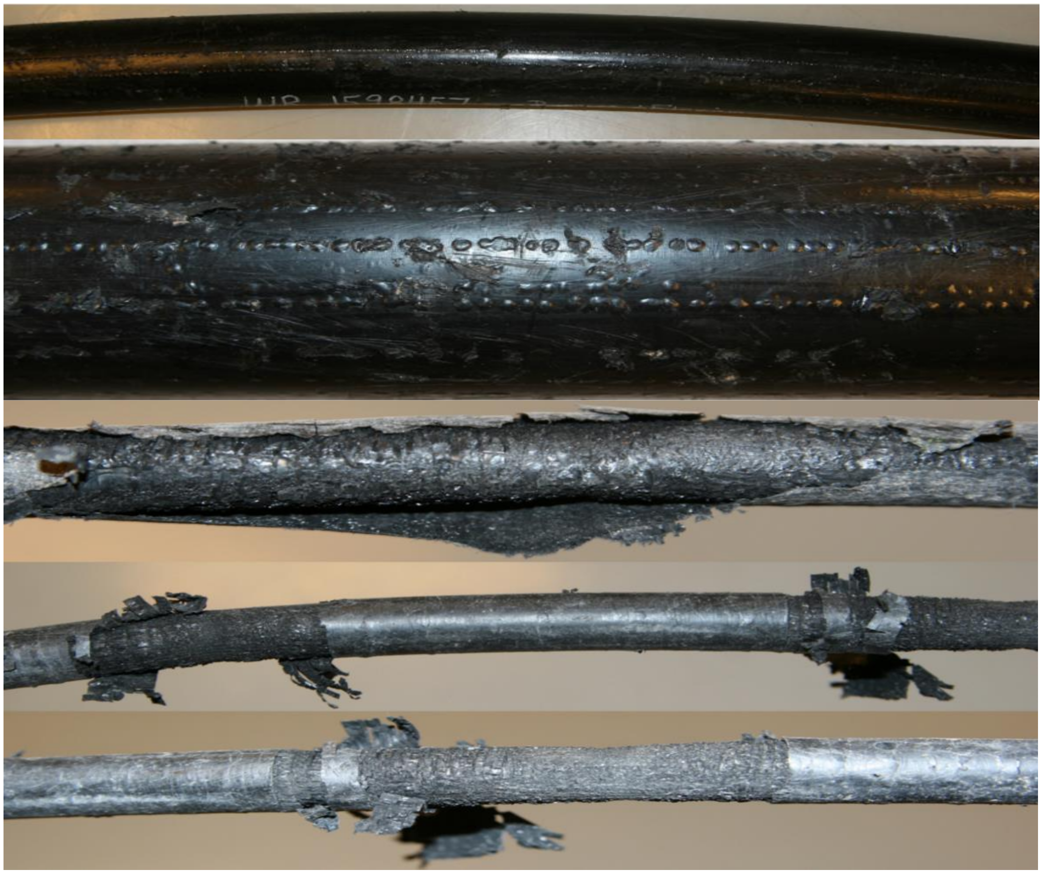
3.2 Degradation due to thermal oxidation.

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.

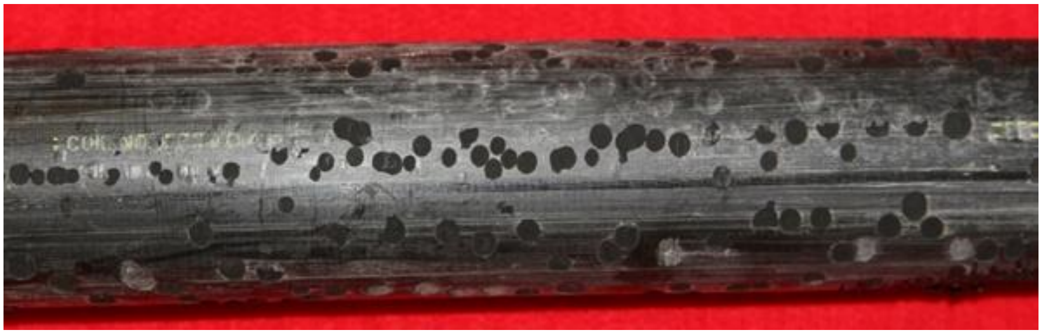
(a) Based on laboratory testing and observed field performance, the regions of the U.S. that have the highest ambient temperature conditions are of particular concern.

(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.**

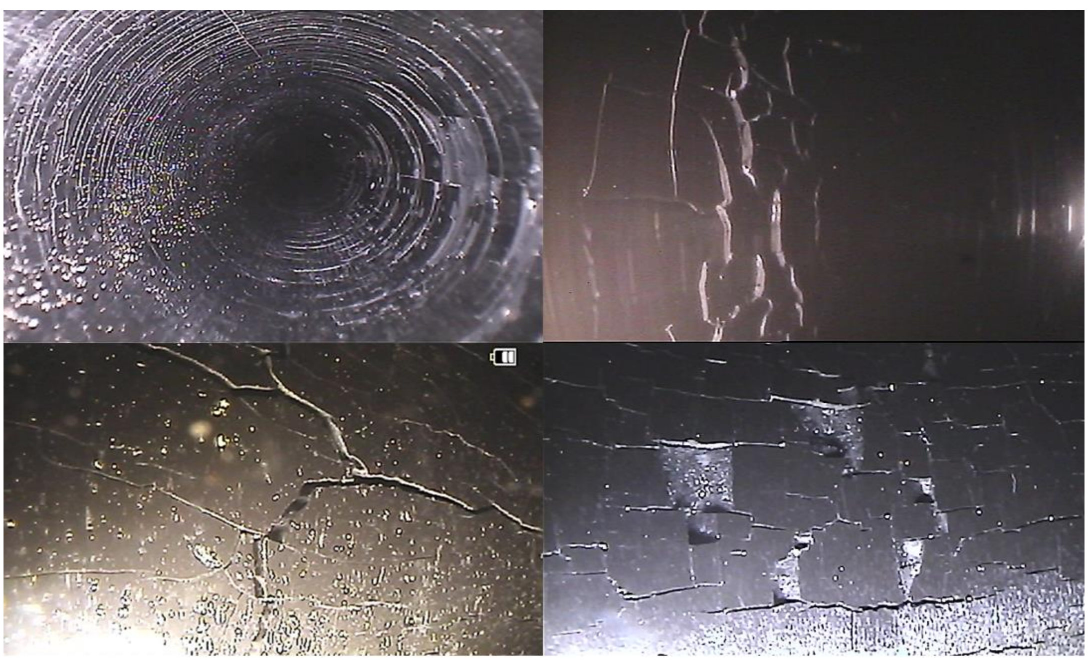


***Note:* Photographs of pipes provided with permission of the operator.**

(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 implementing the following practices as applicable.

(1) Visually inspect Driscopipe® 7000 or 8000 while conducting normal operations and maintenance activities.

(2) During squeeze offs, the operator should listen for cracking.

(3) Operators in warmer regions of the U.S. should conduct random sampling and testing of pipe in areas at higher risk for thermal degradation considering the factors stated above.

(4) Operators in high temperature regions, such as the desert southwest and southern-most regions of the U.S. should sample and test when the opportunity arises and where appropriate, prepare and implement mitigative activities based on their DIMP.

(f) Methods of evaluating or identifying Driscopipe® 7000 and 8000 HDPE pipe for thermal oxidation include the following.

(1) Visual inspection of affected pipe for blistering, delamination, or peeling of the external or internal surfaces.

(2) Listening for popping or crunching sounds during the squeezing of the pipe.

(3) Bend-back testing per ASTM D2513 (Section 5.12); affected pipe is likely to show signs of cracking or crazing.

(4) Oxidative induction time (OIT) testing per ASTM D3895 conducted on the external and internal surfaces. An OIT value of five minutes or less is indicative of significant stabilizer depletion in the pipe and such values warrant other mitigation measures.

(5) Fourier transform infrared (FTIR) spectroscopy testing might show possible carbonyl peaks at 1711-1715cm^{-1}. As peaks due to the additives of the compound might also show up in this range, further evaluation is required to confirm the presence of degradation.

(g) For additional information, see OPS Advisory Bulletin ADB-2012-03 (77 FR, 13387, Mar. 6, 2012; for reference Guide Material Appendix G-192-1, Section 2).

4 STEEL TRANSMISSION LINES - STRESS CORROSION CRACKING (SCC)

4.1 SCC.

SCC is a form of environmentally assisted cracking (EAC), a generic term to describe all types of cracking in pipelines where the surrounding environment, pipe material, and stress act together to reduce the pipe strength or load-carrying capacity. Stress corrosion cracks typically occur in a colony or cluster, and stress and corrosion work together to weaken the pipe. The tensile stresses required to initiate SCC may result from directly applied stresses (pressure and overburden) or residual stresses (fabrication and construction). If not mitigated, cracks may grow to sizes that threaten the integrity of a pipeline.

(a) Types of SCC.

Two types of SCC may be found on underground steel pipe.

(1) "Near-neutral pH SCC," also known as low-pH or non-classical SCC, with the following basic characteristics.

(i) Transgranular.

(ii) Limited branching.

(iii) Associated with some corrosion of the crack walls and pipe surface.

(iv) Associated with a near-neutral electrolyte (pH 6.0 to 8.0).

(2) "High pH SCC," also known as classical SCC, with the following basic characteristics.

(i) Intergranular.

(ii) Typically branched.

(iii) Associated with an alkaline electrolyte (pH 9.0 to 11.0).

Table 192.613i below summarizes the characteristics of near-neutral pH SCC and high pH SCC.

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) Tenants that are not direct gas customers occupying multi-family residential building/units or multi-commercial units. Operators should also consider notifying those residents and business owners who may be renters or leaseholders along its pipelines that might not be direct customers of a gas distribution operator. This group might include the following.
   (1) Working in subdivided buildings or office campuses or complexes.
   (2) Residing in apartments, student housing, transitional housing, rental units, or other types of residential units.

(c) Emergency officials and local public officials with land use authority.
See 2.3(c) of the guide material under §192.614.

(d) Excavators.
See 2.3(a) of the guide material under §192.614.

(e) 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) Communicate periodic messages to the known excavator community in their territory. The message should inform excavators of the requirement to promptly report damages that result in the release of gas (especially if required by state regulations) to appropriate emergency response authorities by calling 911 (49 CFR §196.109) or, where there is no local 911, the local emergency response agency.
    (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) Communicate periodic messages to the known excavator community in their territory. The message should inform excavators of the requirement to promptly report damages that result in the release of gas (especially if required by state regulations) to appropriate emergency response authorities by calling 911 (49 CFR §196.109) or, where there is no local 911, the local emergency response agency.
    (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.
(i) Planned rolling electric system blackouts or unplanned electric system outages, large-scale or small-scale, might result in the interruption of gas service. The duration of the gas service interruption might exceed the duration of the electric system outage due to the turn-on and turn-off process of gas restoration.

2.5 Message delivery methods.

Guidance is provided in API RP 1162, Section 5 and Appendix D 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: 10/05/22]

(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 Appendix G-192-8, Section 10.

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, consider following the evaluation steps in 9 below.

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 CONSIDERATIONS FOR MECHANICAL FITTINGS

If the cause of a mechanical fitting failure is not readily apparent in the field and the operator chooses to conduct further evaluation off-site, the following is provided for evaluating either a nut-follower or a stab-type fitting. Other compression fittings, if investigated for failure, can follow the same basic principles as covered below. Participation by the manufacturer or referencing the manufacturer's literature (if available) early in the investigation can provide more accurate information.

9.1 Mechanical fitting failure evaluation for nut-follower fittings.

(a) Before disassembly, the operator should:
- (1) Use a checklist to capture as much information as practicable.
- (2) Mark the 12 o'clock position of fitting with the pipe component while the unit is still in place.
- (3) Photograph and document external observations, both at the failure site before cutting out and then at the evaluation facility.
- (4) After proper shutdown and purge of gas, cut out the fitting without disturbing the pipe connection and transport the unit to the evaluation location. Do not attempt to disassemble in the field.
- (5) Document whether any external blocking or restraint devices were found in the field.
- (6) Classify and document the surrounding soil.
- (7) Contact the manufacturer if the problem appears to be with the integrity of the fitting.
- (8) Document whether any wrench marks or other surface damages are on the fitting body.
- (9) Document whether nuts on bolted-type fittings appear to be evenly tightened.
- (10) Document pipe and fitting characteristics, such as nominal size, SDR, schedule, and wall thickness.
- (11) Document the "printline" marking on pipe and fitting.
- (12) Document observations, such as cracking, delamination, and sand holes.
- (13) Document leak path location.
  - (i) Leak through fitting body – Fitting failure.
  - (ii) Leak through sealing area – Joint Failure.
- (14) Determine an unknown leak path with a method such as the following.
  - (i) Cap the unit using test fittings.
  - (ii) Inject a fluorescein solution into the assembly and gradually pressurize.
  - (iii) Illuminate with UV light and identify specific leak path.
  - (iv) Drain fluorescein and allow time to dry before disassembling. Dry fluorescein in the leak path may be visible after disassembly. This is particularly important in cases where scratches on pipe create a leak path.
- (15) Mark pipe and fitting for stab depth and apparent leak location.
- (16) Mark the position of nuts or followers.
- (17) Photograph again.
- (18) Test the torque on nuts or followers, if appropriate.
- (19) For a pullout failure:
  - (i) Examine pipe surface for marks or indentations indicating excavation damage.
  - (ii) Record position of stiffener relative to pipe end.

(b) During assembly, the operator should:
- (1) Maintain relative position of pipe, fitting, and components as practicable.
- (2) Not saw or cut into fitting or pipe unless necessary. If necessary, do so in a manner that allows position of components to be accurately determined after disassembly.
- (3) Count turns required to remove nuts or bolts. Precision down to 1/16th turn or better is helpful.
- (4) Compare the actual turns found to those recommended by manufacturer. If uncertain, contact the manufacturer.

(c) After assembly, the operator should:
  (1) As soon as practicable, take high-resolution, close-up photographs of external and internal surfaces of pipe and components to record indentations and other evidence.
  (2) Document any damaged, cut, or distorted components.
  (3) Verify the leak path, such as looking for fluorescein traces on pipe and sealing member under UV light.
  (4) Record the condition of the internal retainer ring since, in some metal mechanical fitting designs, deformation of the internal retainer ring is evidence that the fitting was improperly torqued at installation. In many cases, the retainer ring might be difficult to remove from the nut if improper torque was applied.
  (5) Document whether the gasket or O-ring appears to be distorted and photograph the condition.
  (6) Document and photograph any scratches on the pipe under the gasket.
  (7) Document whether there is dirt or other debris between the gasket and pipe.
  (8) Document whether scratches, dirt, or debris line up with the fluorescein traces.
  (9) For a pullout failure:
    (i) Take note of any indicators on pipe surface of gradual or sudden movement of pipe relative to fitting.
    (ii) Determine whether the joining procedure used was qualified in accordance with §192.283(b).
  (10) Document whether all components are present and in correct orientation.
  (11) Document whether the correctly sized stiffener was used for the plastic piping being connected.
  (12) Document whether the joining procedure was qualified per §192.283(b).
  (13) Use the documented findings to help identify the apparent cause of mechanical joint failure.

9.2 Mechanical fitting failure evaluation for boltless stab fittings (2-inch and smaller).

The operator should:

(a) Use a checklist to capture as much information as practicable.
(b) Mark the 12 o'clock position of fitting with the pipe component while the unit is still in place.
(c) Photograph and document external observations, both at the failure site before cutting out and then at the evaluation facility.
(d) After proper shutdown and purge of gas, cut out the fitting without disturbing the pipe connection and transport the unit to the evaluation location. The operator should not attempt to disassemble in the field.
(e) Document whether any external blocking or restraint devices were found in the field.
(f) Classify and document the surrounding soil.
(g) Contact the manufacturer if the problem appears to be with the integrity of the fitting.
(h) Document whether any wrench marks are on the fitting body.
(i) Cut fitting in half.
(j) Determine whether the chamfer was proper for the installed fitting: internal for internal O-ring seal and external for external seal.
(k) Document whether the pipe was cut square.
(l) Document the condition of O-rings (e.g., torn, pinched).
(m) Document the condition of pipe external wall surface and quantify the presence of scratches or gouges.

10 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):

(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

1 GENERAL

This section applies to onshore steel transmission pipeline segments. MAOP reconfirmation is also applicable to transmission line pipe and non-line pipe components within appurtenant facilities including compressor, meter, and pressure limiting stations. MAOP reconfirmation is required (§192.624(a)) for pipeline segments with non-TVC MAOP records located within the following areas.

Applicability	Pipeline Location
MAOP Records (§ 192.619(a)(2)) not Traceable, Verifiable, and Complete (TVC)	High Consequence Area
	Class 3 Location
	Class 4 Location
Pipelines with MAOP Grandfathered by §192.619(c) and ≥ 30% SMYS	High Consequence Area
	Class 3 Location
	Class 4 Location
	Moderate Consequence Area and ILI-capable

(a) Traceable, Verifiable, and Complete (TVC) Records Considerations – Operators may consider the following definitions that are taken from the PHMSA preamble to the Final Rule of Amendment 192-125:

(1) Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, which include mechanical and chemical properties; purchase requisition; or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.

(2) Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a pipeline segment complemented by pressure charts or field logs. Another

example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipeline segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by a qualified individual who observed the test or inspection being performed.

(3) Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking such as a corporate stamp or seal. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipeline segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.

(4) A single record may be confirmed as being TVC.

(5) Pressure test records must meet the requirements of § 192.619(a)(2).

(b) For pipelines that have TVC test records in accordance with §192.619(a)(2), but tested prior to July 1, 1965, the confirmed MAOP is restricted to §192.619(a)(3) (the lowest of §192.619(a)).

2 PROCEDURES AND COMPLETION DATES

(a) Operators will be required to report annual MAOP reconfirmation progress to PHMSA as part of the annual submittal of Form F 7100.2-1 (PHMSA Annual Report for Natural and Other Gas Transmission and Gathering Pipeline Systems).

(b) If a pipeline segment requires MAOP reconfirmation due to a change in location class, then operators must confirm or revise the MAOP for that segment within 24 months. This follows §§192.609 and 192.611 timeframes.

3 RECONFIRMATION METHODOLOGIES – CLARIFICATIONS AND CONSIDERATIONS

(a) Method 1 – Pressure Test.
If any of the records are not TVC, then missing records must be obtained and/or material attributes verified in accordance with § 192.607 (§192.624(c)(1)).

(b) Method 2 – Pressure Reduction.
The minimum cumulative duration of eight hours where the highest actual sustained pressure must have been reached during the continuous 30-day period (§192.624(c)(2)). The eight-hour period does not need to be continuous; it can be made up of shorter periods that over the course of 30 days amount to at least eight hours above a certain pressure. Sustained pressure may be substantiated using operator's pressure logs for the pipeline (e.g., SCADA data, pressure measurement points).

(c) Method 3 – Engineering Critical Assessment (ECA).

(1) Operators should consider developing procedures on how to conduct an ECA within their organization.

(2) Examples of technically proven models for calculating predicted failure pressures include those listed below. Other methods must use a technically proven fracture mechanics model appropriate to the failure mode, material properties, and boundary condition used (pressure test, ILI) (§192.632).

(i) Brittle Failure.
- (A) Newman-Raju Model
- (B) PipeAssess PI™

(ii) Ductile Failure.
- (A) Modified Log-Secant Model
- (B) API 579 – Level II or Level III
- (C) CorLas™

(D) PAFFC Model
(E) PipeAssess PI™

(3) See guide material under §192.632.

(d) Method 4 – Pipe Replacement.

(e) Method 5 – Pressure Reduction for Pipeline Segments with Small Potential Impact Radius (PIR). The minimum cumulative duration of eight hours where the highest actual sustained pressure must have been reached during the continuous 30-day period (§192.624(c)(5)). The eight-hour period does not need to be continuous; it can be made up of shorter periods that over the course of 30 days amount to at least eight hours above a certain pressure. Sustained pressure may be substantiated using operator's pressure logs for the pipeline (e.g., SCADA data, pressure measurement points).

(f) Method 6 – Alternative Technology.
If no response is provided by PHMSA within the 90-day timeframe subsequent to notification, then operators may proceed with the use of the alternative technology (§192.18).

(g) Operators should consider developing a process or decision matrix for reconfirmation method selection and pipeline segment prioritization. The following factors should be considered in the development.
(1) History of the pipeline segment and current pipeline conditions.
(2) Reliability and resiliency of the impacted pipeline network.
(3) Ability to take a pipeline out of service for pressure testing (feasibility of Method 1).
(4) Pressure reduction impacting the ability to run an in-line inspection (ILI) tool (feasibility of Methods 2 and 5).
(5) Ability to accommodate the passage of an ILI tool or availability of assessment tools (feasibility of Method 3).
(6) Constructability (e.g., pipeline accessibility, permitting).
(7) Impact to customers, the public, and the environment (e.g., service interruptions, sensitive areas).
(8) Cost management.
(9) Specific PHMSA requirements (e.g., deadlines).

4 RECORDS

Records for abandoned pipelines do not need to be retained.

§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."

§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 April 10, 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) 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.

§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

(1) See Guide Material Appendix G-192-17 for the explicit requirements of each patrol, survey, inspection, or test required by Subparts L and M.

(2) 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.

(3) See guide material under §192.227 for records demonstrating the qualification of each individual welder at the time of construction of steel transmission and regulated gathering lines.

(4) See §192.285(e) for records demonstrating the qualification of each individual plastic pipe joiner at the time of construction of plastic transmission line.

§192.710

Transmission lines: Assessments outside of high consequence areas.

[Effective Date: 05/24/23]

(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, 192.712, 192.713, and 192.714 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, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

This guide material is under review following Amendment 192-125

(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 <u>http://www.npms.phmsa.dot.gov</u> 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.

(c) Abandonment should not be considered complete until the gas or liquid hydrocarbons contained within the abandoned section poses no potential hazard. An operator should consider diameter, length, location, or other parameters when identifying piping to be abandoned that needs to be purged.

(d) Pipelines 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 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 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.

2.3 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.

2.4 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.

2.5 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,

§192.925

What are the requirements for using External Corrosion Direct Assessment (ECDA)?

Effective Date: 10/01/15]

(a) *Definition*. ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

(b) *General requirements*. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4, and in NACE SP0502 (incorporated by reference, *see* §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect inspection, direct examination, and post assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage and to address the threat as required by §192.917(e)(1).

(1) *Preassessment*. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 3, the plan's procedures for preassessment must include —

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE SP0502, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) *Indirect inspection*. In addition to the requirements in ASME/ANSI B31.8S, section 6.4 and in NACE SP0502, section 4, the plan's procedures for indirect inspection of the ECDA regions must include —

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(3) *Direct examination*. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 5, the plan's procedures for direct examination of indications from the indirect examination must include —

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE SP0502), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502);

(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE SP0502.

(4) *Post assessment and continuing evaluation*. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include —

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in §192.939. (See Appendix D of NACE SP0502.)

[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. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

Note: References to NACE throughout this section of guide material are specific to the edition of NACE SP0502 as incorporated by reference (IBR) in §192.7. Abbreviated references are used in guide material below. Example: "NACE 5.2.1" means NACE SP0502, Paragraph 5.2.1 of the IBR edition. See 3 of the guide material under §192.907. NACE SP0502 is an IBR standard; therefore, "shall", "requires", or "must" statements in this section of guide material with specific reference to NACE SP0502 are required to be followed per §192.925(b).

1 PURPOSE

External Corrosion Direct Assessment (ECDA) is a methodology to assess the integrity of pipe and pipe coating that is subject to the threat of external corrosion. ECDA can discover existing external corrosion on steel and other ferrous pipe. A key advantage of ECDA, when compared to in-line inspection (ILI) and pressure testing, is its ability to detect coating damage before corrosion occurs.

2 GENERAL REQUIREMENTS

(a) A written ECDA plan is required to be based on the following.
 (1) Section 192.925.
 (2) ASME B31.8S-2004, Paragraph 6.4 (see §192.7 for IBR).
 (3) NACE SP0502.
(b) The ECDA plan should include its purpose, objectives, and instructions to personnel.
(c) Written procedures are required to address the following four process steps (see §192.925(b)).
 (1) Pre-assessment.
 (2) Indirect inspection.
 (3) Direct examination.
 (4) Post-assessment and continuing evaluation.
(d) Section 192.947(d) requires documents to support decisions, analyses, and processes developed and used to implement and evaluate the operator's integrity management program including ECDA.
(e) The ECDA plan may reference appropriate sections of other documents (e.g., survey procedures) instead of including them in the ECDA plan. These documents should be available to personnel performing associated tasks.
(f) For first-time application of ECDA on a covered segment, the written procedure is required to address more restrictive criteria for each step of the ECDA assessment except for post-assessment.

2 MAXIMUM REASSESSMENT INTERVALS

(a) Tables 192.939i through 192.939iv and Appendix E to Part 192 list the maximum permitted reassessment intervals based on type of prior assessment and operating stress level. If the maximum permitted time interval for an assessment method exceeds 7 calendar years, a confirmatory direct assessment (see §192.931 regarding CDA) or other assessment must be conducted at intervals not exceeding 7 calendar years (§192.939(a) and (b)).

(b) Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to PHMSA-OPS, in accordance with §192.18, with sufficient justification of the need for the extension (§192.939(a) and (b)). The operator should state why the extension is needed and how it will not compromise safety. Additional actions to ensure public safety (e.g., leak surveys, patrols) during the extension should also be considered and noted in the application. The following are examples of what might be considered as sufficient justification for an extension.
(1) Weather-related or natural disaster conditions.
(2) Assessment tool availability or malfunctions.
(3) Changes in field or operating conditions.
(4) Gas supply issues.
(5) Permitting issues.
(6) Public health concerns, such as a pandemic.

(c) Based on the threats and conditions found, reassessment may be required at intervals less than the maximum.

MAXIMUM REASSESSMENT INTERVALS FOR IN-LINE INSPECTION (ILI)			
Stress Level	**Ratio of Predicted Failure Pressure (FP) of Remaining Defects to the MAOP**	**<u>Maximum Interval</u>** Based on prior assessments, data integration, and risk assessment using reasonably anticipated or scientifically proven rate of defect growth. [§192.939(a)(1)(i)]	**<u>Maximum Interval</u>** Based on ASME B31.8S-2004, Section 5, Table 3 (see §192.7 for IBR). [§192.939(a)(1)(ii)]
≥ 50% SMYS	FP exceeds 1.25 times MAOP	7 years	5 years
	FP exceeds 1.39 times MAOP	10 years	10 years
< 50% and ≥ 30% SMYS	FP exceeds 1.4 times MAOP	15 years	5 years
	FP exceeds 1.7 times MAOP	15 years	10 years
	FP exceeds 2.0 times MAOP	15 years	15 years
< 30% SMYS (Low stress reassessment may be used; see §192.941)	FP exceeds 1.7 times MAOP	20 years	5 years
	FP exceeds 2.2 times MAOP	20 years	10 years
	FP exceeds 2.8 times MAOP	20 years	15 years
	FP exceeds 3.3 times MAOP	20 years	20 years

TABLE 192.939i

<table>
<tr><th colspan="3">MAXIMUM REASSESSMENT INTERVALS FOR PRESSURE TESTING</th></tr>
<tr><th>Stress Level</th><th>Ratio of test pressure (TP) to the MAOP</th><th>Maximum Interval</th></tr>
<tr><td rowspan="2">≥ 50% SMYS</td><td>Testing in accordance with Subpart J</td><td>7 years</td></tr>
<tr><td>TP exceeds 1.39 times MAOP</td><td>10 years</td></tr>
<tr><td rowspan="3">< 50% and ≥ 30% SMYS</td><td>Testing in accordance with Subpart J</td><td>7 years</td></tr>
<tr><td>TP exceeds 1.7 times MAOP</td><td>10 years</td></tr>
<tr><td>TP exceeds 2.0 times MAOP</td><td>15 years</td></tr>
<tr><td rowspan="4">< 30% SMYS
(Low stress reassessment may be used; see §192.941)</td><td>Testing in accordance with Subpart J</td><td>7 years</td></tr>
<tr><td>TP exceeds 2.2 times MAOP</td><td>10 years</td></tr>
<tr><td>TP exceeds 2.8 times MAOP</td><td>15 years</td></tr>
<tr><td>TP exceeds 3.3 times MAOP</td><td>20 years</td></tr>
</table>

TABLE 192.939ii

MAXIMUM REASSESSMENT INTERVALS FOR EXTERNAL CORROSION DIRECT ASSESSMENT		
Stress Level	**Results of Examinations**	**Maximum Interval**
≥ 50% SMYS	No corrosion defects found	10 years
	Corrosion defects found	Minimum of calculated remaining half-life or 10 years
< 50% and ≥ 30% SMYS	No corrosion defects found	15 years
	Corrosion defects found	Minimum of calculated remaining half-life or 15 years
< 30% SMYS (Low stress reassessment may be used; see §192.941)	No corrosion defects found	20 years
	Corrosion defects found	Minimum of calculated remaining half-life or 20 years

TABLE 192.939iii

MAXIMUM REASSESSMENT INTERVALS FOR INTERNAL CORROSION DIRECT ASSESSMENT AND STRESS CORROSION CRACKING DIRECT ASSESSMENT				
Stress Level	**ICDA**		**SCCDA**	
	Results of Examinations	**Maximum Interval**	**Results of Examinations**	**Maximum Interval**
> 50% SMYS	Critical angle examined	10 years	All indications examined	10 years
			All indications not examined	Lower of calculated remaining half-life or 5 years
< 50% and > 30% SMYS	Critical angle examined	15 years	All indications examined	15 years
			All indications not examined	Lower of calculated remaining half-life or 10 years
< 30% SMYS (Low stress reassessment may be used; see §192.941)	Critical angle examined	20 years	All indications examined	20 years
			All indications not examined	Lower of calculated remaining half-life or 10 years

TABLE 192.939iv

3 NEED FOR MORE FREQUENT ASSESSMENT

The reassessment intervals listed in Tables 192.939i through 192.939iv represent the maximum interval between assessments. Reassessment at a shorter interval should be considered for any of the following.

(a) The operator plans on increasing the MAOP of the pipeline.
(b) The stresses leading to cyclic fatigue are increased, and the pipe is subject to manufacturing threats (e.g., low-frequency ERW seams), construction threats (e.g., wrinkle bends), or other similar threats.
(c) A failure has occurred on the pipeline segment.
(d) Failure on another pipeline segment with similar characteristics that could indicate a similar threat to the covered segment.
(e) Known defects that need to be addressed prior to the maximum reassessment interval.

4 PERFORMANCE-BASED PROGRAMS

The maximum reassessment intervals listed in Tables 192.939i through 192.939iv may be exceeded by an operator that can demonstrate exceptional performance as listed in §192.913(b). One requirement for using a performance-based program is that the operator must have completed at least 2 assessments for each covered segment to be included in the performance-based program. When using longer assessment intervals under a performance-based program, an operator must be able to provide analysis supporting the longer interval, and must perform confirmatory direct assessment at intervals not exceeding 7 calendar years (§192.939(a) and (b)). Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to PHMSA-OPS, in accordance with §192.18, with sufficient justification of the need for the extension (§192.939(a) and (b)).

5 WAIVER (SPECIAL PERMIT) FOR DEVIATION FROM REASSESSMENT INTERVALS

Operators can apply to PHMSA-OPS for waivers (special permits) if the reassessment interval cannot be met due to lack of availability of assessment tools or the need to maintain product supply. See §192.943 for the waiver process and §190.341 for the required content of applications for special permits.

§192.941

What is a low stress reassessment?

[Effective Date: 05/24/23]

(a) *General*. An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with §192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§192.919 and 192.921.

(b) *External corrosion*. An operator must take one of the following actions to address external corrosion on the low stress covered segment.

(1) *Cathodically protected pipe*. To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an indirect assessment on the covered segment at least every once 7 calendar years. The indirect assessment must be conducted using one of the following means: indirect examination method, such as a close interval survey; alternating current voltage gradient survey; direct current voltage gradient survey; or the equivalent of any of these methods. An operator must evaluate the cathodic protection and corrosion threat for the covered segment and include the results of each indirect assessment as part of the overall evaluation. This evaluation must also include, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where external corrosion assessments*

distribution pipeline: Corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other issues that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) *Evaluate and rank risk.* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

(d) *Identify and implement measures to address risks.* Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).

(e) *Measure performance, monitor results, and evaluate effectiveness.*

(1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(i) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(iv) Total number of leaks either eliminated or repaired, categorized by cause;

(v) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material; and

(vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

(f) *Periodic Evaluation and Improvement.* An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(g) *Report results.* Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by §191.11. An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

[Issued by Amdt. 192-113, 74 FR 63906, Dec. 4, 2009 with Amdt. 192-113 Correction, 75 FR 5244, Feb. 2, 2010; Amdt. 192-116, 76 FR 5494, Feb. 1, 2011]

GUIDE MATERIAL

See Guide Material Appendices G-192-3 and G-192-8.

§192.1009

Removed and Reserved

[Effective Date: 03/12/21]

§192.1011

What records must an operator keep?

[Effective Date: 02/12/10]

An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.

[Issued by Amdt. 192-113, 74 FR 63906, Dec. 4, 2009 with Amdt. 192-113 Correction, 75 FR 5244, Feb. 2, 2010]

GUIDE MATERIAL

See Guide Material Appendix G-192-8.

§192.1013

When may an operator deviate from required periodic inspections under this part?

[Effective Date: 02/12/10]

(a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart.

(b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency. The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

(c) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

[Issued by Amdt. 192-113, 74 FR 63906, Dec. 4, 2009 with Amdt. 192-113 Correction, 75 FR 5244, Feb. 2, 2010]

GUIDE MATERIAL APPENDIX G-191-2

(See guide material under §§191.9, 191.11, 191.15, and 191.17)

INDEX OF PHMSA REPORT FORMS

This appendix an index of PHMSA forms and the code sections in which they are referenced.

PHMSA Form Number*	Form Title	Code Section(s) Referencing the Form
F 1000.1	Operator Assignment Request	191.21, 191.22
F 1000.2	Operator Registry Notification	191.22
F 7100.1	Gas Distribution System (Incident Report)	191.9, 191.21
F 7100.1-1	Gas Distribution System (Annual Report)	191.11, 191.21
F 7100.2	Gas Transmission and Gathering Systems (Incident Report) **	191.15, 191.21
F 7100.2-1	Gas Transmission and Gathering Systems (Annual Report)	191.17, 191.21, 192.945
F 7100.3	Liquefied Natural Gas (LNG) Facilities (Incident Report)	191.15, 191.21
F 7100.3-1	Liquefied Natural Gas (LNG) Facilities (Annual Report)	191.17, 191.21
F 7100.4-1	Underground Natural Gas Storage Facility (Annual Report)	191.17

* Latest versions of forms and instructions are available at www.phmsa.dot.gov/forms/pipeline-forms.
** Includes underground natural gas storage.

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1.5 FITTINGS: THREADED & SOCKET-WELD (Continued)		
ASME B16.15	Cast Copper Alloy Threaded Fittings: Classes 125 and 250	§192.149
ASTM A733	Welded and Seamless Carbon Steel and Austenitic Stainless Steel Pipe Nipples	§192.149
MSS SP-79	Socket-Welding Reducer Inserts	§192.149
MSS SP-83	Class 3000 and 6000 Steel Pipe Unions, Socket Welding and Threaded	§192.149
1.6 FITTINGS: WELDED		
ASME B16.9	Factory-Made Wrought Buttwelding Fittings	§192.149
ASME B16.25	Buttwelding Ends	
ASME B16.49	Factory-Made, Wrought Steel, Buttwelding Induction Bends for Transportation and Distribution Systems	§192.149
MSS SP-75	High-Strength Wrought, Butt-Welding Fittings	§192.149 §192.157
1.7 MATERIALS & FITTINGS: MISCELLANEOUS		
ANSI A21.14	Ductile Iron Fittings, 3-Inch Through 24-Inch for Gas (Revised 1989; Withdrawn 1994)	
ASME B16.18	Cast Copper Alloy Solder Joint Pressure Fittings	
ASME B16.22	Wrought Copper and Copper Alloy Solder-Joint Pressure Fittings	
ASTM A105	Carbon Steel Forgings for Piping Applications	
ASTM A181	Carbon Steel Forgings for General-Purpose Piping	
ASTM A182	Forged or Rolled Alloy and Stainless Steel Pipe Flanges, Forged Fittings, and Valves and Parts for High-Temperature Service	
ASTM A234	Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and High Temperature Service	
ASTM A350	Carbon and Low-Alloy Steel Forgings, Requiring Notch Toughness Testing for Piping Components	
ASTM A403	Wrought Austenitic Stainless Steel Piping Fittings	
ASTM A420	Piping Fittings of Wrought Carbon Steel and Alloy Steel for Low-Temperature Service	
AWWA C111 / ANSI 21.11	Rubber-Gasket Joints for Ductile-Iron Pressure Pipe and Fittings	GMA G-192-1A

Table Continued

1.7 MATERIALS & FITTINGS: MISCELLANEOUS (Continued)		
AWWA Manual M41	Ductile-Iron Pipe and Fittings	
MSS SP-6	Standard Finishes for Contact Faces of Pipe Flanges and Connecting-End Flanges of Valves and Fittings	§192.147
1.8 BOLTS & GASKETS		
AGA CPR-83-4-1	Threaded Fasteners Torquing *(Available on GPTC website under Reports and Position Papers)*	
ASME B1.1	Unified Inch Screw Threads (UN and UNR Thread Form)	§192.147
ASME B16.20	Metallic Gaskets for Pipe Flanges	§192.147
ASME B16.21	Non-metallic Flat Gaskets for Pipe Flanges	
ASME B18.2.1	Square, Hex, Heavy Hex, and Askew Head Bolts and Hex, Heavy Hex, Hex Flange, Lobed Head, and Lag Screws (Inch Series)	§192.147
ASME B18.2.2	Nuts for General Applications: Machine Screw Nuts, Hex, Square, Hex Flange, and Coupling Nuts (Inch Series)	§192.147
ASTM A193	Alloy-Steel and Stainless Steel Bolting for High-Temperature or High Pressure Service and Other Special Purpose Applications	§192.147
ASTM A194	Carbon, Alloy Steel, and Stainless Steel Nuts for Bolts for High-Pressure or High-Temperature Service, or Both	§192.147
ASTM A307	Carbon Steel Bolts, Studs, and Threaded Rod 60,000 PSI Tensile Strength	§192.147
ASTM A320	Alloy-Steel and Stainless Steel Bolting for Low-Temperature Service	§192.147
ASTM A354	Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners	§192.147
ASTM A449	Hex Cap Screws, Bolts and Studs, Steel, Heat Treated, 120/105/90 ksi Minimum Tensile Strength, General Use	§192.147
1.9 CORROSION RELATED		
ASME STP-PT-011	Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas	§192.613 §192.929
ASTM B117	Standard Practice for Operating Salt Spray (Fog) Apparatus	§192.461
CEPA	Stress Corrosion Cracking Recommended Practices, 2nd Ed	§192.929
GTI-04/0071	External Corrosion Direct Assessment (ECDA) Implementation Protocol	
NACE MR0175	Materials for Use in H_2S-Containing Environments in Oil and Gas Production	§192.53 §192.475

1.9 CORROSION RELATED (Continued)		
NACE RP0175	Control of Internal Corrosion in Steel Pipelines and Piping Systems (Revised 1975; Discontinued)	§192.475
NACE SP0102	In-Line Inspection of Pipelines	§192.476 GMA G-192-14
NACE SP0106	Control of Internal Corrosion in Steel Pipelines and Piping Systems	§192.476 §192.917
NACE SP0113	Pipeline Integrity Method Selection	§192.925
NACE SP0169	Control of External Corrosion on Underground or Submerged Metallic Piping Systems	§192.453 §192.455 §192.461 §192.463 §192.473 §192.620 App. D
NACE SP0177	Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems	§192.467
NACE SP0188	Discontinuity (Holiday) Testing of New Protective Coatings on Conductive Substrates	§192.461
NACE SP0192	Monitoring Corrosion in Oil and Gas Production with Iron Counts	§192.475 §192.917
NACE SP0200	Steel-Cased Pipeline Practices	§192.323 §192.467
NACE SP0204	Stress Corrosion Cracking (SCC) Direct Assessment Methodology	§192.613 §192.917 §192.929
NACE SP0206	Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)	§192.476 §192.927
NACE SP0207	Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines	§192.925 §192.941
NACE SP0274	High-Voltage Electrical Inspection of Pipeline Coatings	§192.461
NACE SP0375	Field-Applied Underground Wax Coating Systems for Underground Pipelines: Application, Performance, and Quality Control	§192.461
NACE SP0394	Application, Performance, and Quality Control of Plant-Applied Single Layer Fusion-Bonded Epoxy External Pipe Coating	§192.461

NACE SP0490	Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coating of 250 to 760 µm (10 to 30 mil)	§192.461
NACE SP0775	Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations	§192.475
NACE TM0109	Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition	§192.467 §192.925 §192.941
NACE TM0194	Field Monitoring of Bacterial Growth in Oilfield Systems	§192.475
Table Continued		

1.9 CORROSION RELATED (Continued)		
NACE TM0497	Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems	§192.467 §192.925
NACE 3D170	Technical Committee Report, Electrical and Electrochemical Methods for Determining Corrosion Rates (Revised 1984; Withdrawn 1994)	§192.475
NACE 3T199	Techniques for Monitoring Corrosion and Related Parameters in Field Applications	§192.476
NACE 35100	In-Line Inspection of Pipelines	GMA G-192-14
NACE 35103	External Stress Corrosion Cracking of Underground Pipelines	§192.613 §192.929
PRCI L52043 / PR-273-0328	SCC Initiation Susceptibility Ranking/Screening	§192.929
SSPC Painting Manual	Good Painting Practice - Volume 1; and Systems and Specifications - Volume 2	§192.479
1.10 DIMENSIONAL STANDARDS		
API Spec 5B	Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads	
ASME B1.20.1	Pipe Threads, General Purpose, Inch	§192.273
ASME B1.20.3	Dryseal Pipe Threads, Inch	
1.11 PLASTIC RELATED		
AGA XR0603	Plastic Pipe Manual For Gas Service	§192.285 §192.321 §192.751 GMA G-192-15B
API Spec 15HR	Guidelines, High-Pressure Fiberglass Line Pipe	§192.917
ASME I00353	Installation of Plastic Gas Pipeline in Steel Conduits Across Bridges	§192.321
ASTM D696	Test Method for Coefficient of Linear Thermal Expansion of Plastics Between -30 ºC and 30 ºC With a Vitreous Silica Dilatometer	§192.281
ASTM D2235	Solvent Cement for Acrylonitrile-Butadiene-Styrene (ABS) Plastic Pipe and Fittings	§192.281
ASTM D2560	Solvent Cements for Cellulose Acetate Butyrate (CAB) Plastic Pipe, Tubing and Fittings (Withdrawn 1986)	§192.281

Table Continued

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 §192.63 §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

1.14 OTHER DOCUMENTS (Continued)		
API Tech Report 5C3	Calculating Performance Properties of Pipe Used as Casing or Tubing	§192.12
API Tech Report 10TR1	Cement Sheath Evaluation	§192.12
API Tech Report 10TR3	Technical Report on Temperatures for API Cement Operating Thickening Time Tests	§192.12
API Tech Report 10TR4	Selection of Centralizers for Primary Cementing Operations	§192.12
API 579	Fitness-for-Service	§192.624
AREMA	Manual for Railway Engineering, Chapter 1 – Roadway and Ballast (for Part 5 – Pipelines)	GMA G-192-15
ASCE 428-5	Guidelines for the Seismic Design of Oil and Gas Pipeline Systems (Discontinued)	§192.103
ASME B31.1	Power Piping	§192.141
ASME B31.2	Fuel Gas Piping (Withdrawn 1988; Replaced by NFPA 54/ANSI Z223.1)	
ASME B31.3	Process Piping	§192.141 §192.159
ASME B31.4	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids	
ASME B31.5	Refrigeration Piping and Heat Transfer Components	§192.141
ASME B31.8S-2010	Managing System Integrity of Gas Pipelines	§192.929
ASME B31.9	Building Services Piping	
ASME B31Q	Pipeline Personnel Qualification	§192.805
ASME CRTD Vol. 57	Determining the Yield Strength of In-Service Pipe	§192.107
ASME CRTD-91	Applications Guide for Determining the Yield Strength of In-Service Pipe by Hardness Evaluation	§192.107
ASME Guide SI-1	ASME Orientation and Guide for Use of SI (Metric) Units	GMA G-192-M
ASNT ILI-PQ	In-line Inspection Personnel Qualification and Certification	GMA G-192-14
ASTM C150/C150M	Standard Specification for Portland Cement	§192.12

1.14 OTHER DOCUMENTS (Continued)		
ASTM D1586	Standard Test Method for Standard Penetration Test (SPT) and Split-Barrel Sampling of Soils	GMA G-192-15A
ASTM D2487	Standard Practice for Classification of Soils for Engineering Purposes (Unified Soil Classification System)	GMA G-192-15A
ASTM D2774	Standard Practice for Underground Installation of Thermoplastic Pressure Piping	§192.321
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	§192.12
ASTM D3967	Standard Test Method for Splitting Tensile Strength of Intact Rock Core Specimens	§192.12
ASTM D4543	Standard Practices for Preparing Rock Core as Cylindrical Test Specimens and Verifying Conformance to Dimensional and Shape Tolerances	§192.12
ASTM D4645	Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method	§192.12
ASTM D6273	Standard Test Methods for Natural Gas Odor Intensity	§192.625
ASTM D7012	Standard Test Methods for Compressive Strength and Elastic Moduli of Intact Rock Core Specimens under Varying States of Stress and Temperatures	§192.12
ASTM D7070	Standard Test Methods for Creep of Rock Core Under Constant Stress and Temperature	§192.12
ASTM E84	Test Method for Surface Burning Characteristics of Building Materials	§192.163
AWS A3.0	Standard Welding Terms and Definitions	§192.3 §192.221
CGA	"Best Practices" Guide	§192.325 §192.361 §192.614
	One Call Systems International (OCSI) Resource Guide	§192.614
CoGDEM	Gas Detection and Calibration Guide	GMA G-192-11 GMA G-192-11A
GRI-91/0283	Guidelines for Pipelines Crossing Railroads	§192.103 GMA G-192-15
GRI-91/0284	Guidelines for Pipelines Crossing Highways	§192.103 GMA G-192-15
GRI-91/0285	Technical Summary and Database for Guidelines for Pipelines Crossing Railroads and Highways	GMA G-192-15

2 GOVERNMENTAL DOCUMENTS (Continued)		
OPS ADB-11-02	Advisory Bulletin – Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems (76 FR 7238, Feb. 9, 2011)	§192.616
OPS ADB-2012-02	Advisory Bulletin – Post-Accident Drug and Alcohol Testing (77 FR 10666, Feb. 23, 2012)	§192.605 §192.615
OPS ADB-2012-03	Advisory Bulletin – Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation (77 FR 13387, Mar. 6, 2012)	§192.613 §192.917
OPS ADB-2012-08	Advisory Bulletin – Inspection and Protection of Pipeline Facilities after Railway Accidents (77 FR 45417, July 31, 2012)	§192.615
OPS ADB-2012-10	Advisory Bulletin – Using Meaningful Metrics in Conducting Integrity Management Program Evaluations (77 FR 72435, Dec. 5, 2012)	GMA G-192-3
OPS ADB-2012-11	Advisory Bulletin – Reporting of Exceedances of Maximum Allowable Operating Pressure (77 FR 75699, Dec. 21, 2012)	§191.23
OPS ADB-2014-03	Advisory Bulletin – Construction Notification (79 FR 54777, Sept. 12, 2014	§191.22
OPS ADB-2014-05	Advisory Bulletin – Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics (79 FR 61937, Oct. 15, 2014)	GMA G-192-3
OPS ADB-2015-02	Advisory Bulletin – Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes (80 FR 36042, June 23, 2015)	§192.615
OPS ADB-2016-05	Advisory Bulletin – Clarification of Terms Relating to Pipeline Operational Status (81 FR 54512, August 16, 2016)	§192.727
OPS ADB-2019-01	Advisory Bulletin – Potential for Damage to Pipeline Facilities Caused by Severe Flooding (84 FR 14715, April 11, 2019)	§192.613 §192.615
OPS ADB-2019-02	Advisory Bulletin – Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards (84 FR 18919, May 2, 2019)	§192.613
OPS ALN-88-01	Alert Notice – Operational failures of pipelines constructed with ERW prior to 1970 (Jan 28, 1988; see document at PHMSA-OPS website)	§192.917

Table Continued

2 GOVERNMENTAL DOCUMENTS (Continued)		
OPS ALN-89-01	Alert Notice – Update to ALN-88-01 (Mar 8, 1989; see document at PHMSA-OPS website)	§192.917
OPS-DOT.RSPA/DMT 10-85-1	Safety Criteria for the Operation of Gaseous Hydrogen Pipelines (Discontinued)	§192.1
OPS TTO No. 5	Technical Task Order – Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Michael Baker Jr., Inc., et al	§192.917
OPS TTO No. 8	Technical Task Order – Stress Corrosion Cracking Study, Michael Baker, Jr., Inc., January 2005	§192.613 §192.917 §192.929
PHMSA-OPS	Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators	GMA G-192-8
	Gas Integrity Management Protocols	§192.925 §192.927
	Guidance Manual for Operators of LP Gas Systems	§192.1 §192.11 §192.616 GMA G-192-8
	Guidance Manual for Operators of Small Natural Gas Systems	§192.1 §192.616 GMA G-192-8
	Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs	§192.925
	Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics	GMA G-192-3
	"Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Gas Pipelines”	§192.620
	Notice – Development of Class Location Change Waiver Criteria (69 FR 38948, June 29, 2004)	§192.611
	Operator Qualification Guidance Manual for Operators of LP Gas Systems	§192.11 §192.801
	Operator Qualification Guide for Small Distribution Systems	§192.801

Table Continued

Site Reference (Continued)	**Website Link**	**Guide Location**
OPS Information Resource Manager Email	InformationResourcesManager@phmsa.dot.gov	§192.727
OPS Integrity Management Database	primis.phmsa.dot.gov/gasimp	§192.949
OPS NPMS homepage	www.npms.phmsa.dot.gov	§192.727
OPS Public Education	primis.phmsa.dot.gov/comm/PublicEducation.htm	§192.616
PHMSA-OPS Annual Report Data	www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids	GMA G-192-8
PHMSA-OPS Guidance Manuals	www.phmsa.dot.gov/training/pipeline/guidance-manuals	§192.1 §192.11 §192.616 §192.801 GMA G-192-8
PHMSA-OPS Guidance for Program Evaluation	www.regulations.gov/document?D=PHMSA-2014-0086-0002 *{then open the attachment}*	GMA G-192-3
PHMSA-OPS Guidance for Small DIMP	https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-distribution-integrity-management/66011/phmsadimpsmalloperatorguidancerev1022813.pdf	GMA G-192-8
PHMSA-OPS Report Forms and Instructions	https://www.phmsa.dot.gov/forms/pipeline-forms	§191.9 §191.11 §191.15 §191.17 §192.945 GMA G-191-2 GMA G-192-8
PPI website	www.plasticpipe.org	GMA G-192-1
PRCI website	www.prci.org	GMA G-192-1
SSPC website	www.sspc.org	GMA G-192-1
TTI website	https://technicaltoolboxes.com/	GMA G-192-1
UL website	www.ul.com	GMA G-192-1
US Government Publications	www.gpo.gov	GMA G-192-1

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Implement an adequate means of tracking and documenting turn-offs. See 1.8(a)(1) of the guide material under §192.615.

8 RESTORATION

In addition to 1.8 of the guide material under §192.615 titled "Restoration of service," consider the following steps.

(a) Restore service in an organized manner. Operators may want to consider the use of an identifier in their customer information system to sort customers affected within isolation areas. A list of high-priority customers, which do not have a working alternate fuel source, should be developed for first restoration. It should include hospitals, nursing homes, customers on life-support equipment, and fire and police departments.
(b) Provide repairs and/or isolation of the damaged area.
(c) If water infiltration was the cause of the outage or water enters the system during the outage, take actions to remove the water. Consider if other actions such as insulation of exposed piping, additional drip maintenance, or alcohol drips will be needed due to higher than normal water vapor in gas flowing through the system.
(d) As warranted, perform a shut-in test or pressure-drop test on the affected area to ensure that all damage to mains and services has been repaired or isolated from the system.
(e) Provide purge points at ends of the system, purge with inert gas where appropriate, and then purge the entire system with gas (see §192.629).
(f) Restore service to individual meters in a systematic way. When restoring service, consideration should be given to the following.
    (1) Presence of any excess flow valves in the system.
    (2) In events such as flooding, water infiltration, and overpressurization, a safety check of all service regulators or appliances, or both, may be necessary.
    (3) Purging of customer piping as warranted.
    (4) A leak check of customer piping as warranted.
    (5) Relighting of all pilots.

9 POST-ASSESSMENT

(a) A post-assessment of the outage recovery should be conducted as soon as practical after restoration and may include assessments of the following.
    (1) Communications prior to and during the outage response.
    (2) Personnel preparedness.
    (3) Equipment availability.
    (4) Material availability.
    (5) Timeline of response activities.
(b) The post-assessment should include recommendations to consider for better preparedness in any future outage situation.

GUIDE MATERIAL APPENDIX G-192-8

(See §§192.1001, 192.1003, 192.1005, 192.1007, 192.1011, 192.1015, and Guide Material Appendix G-192-8A)

DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM (DIMP)

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1 INTRODUCTION

1.1 Scope.

(a) This guide material is intended to assist operators with development of a Distribution Integrity Management Program (DIMP), including the written plan, and compliance with Federal Regulations §§192.1001, 192.1003, 192.1005, 192.1007, 192.1011, and 192.1015 on DIMP. It provides operators with practices that may be considered as they develop and maintain a DIMP specific to their gas distribution systems.

(b) Distribution pipeline systems and associated operating practices can vary widely. Examples of system differences include: materials used, age, manner of construction, operation and maintenance practices, and operating environments (natural and man-made). This guidance recognizes that there is wide diversity among distribution systems and is therefore flexible, allowing operators to identify considerations dealing with their unique threats and to select actions suited to their specific needs.

(c) The options in this guidance are intended to provide the operator with a selection of possible choices to use in improving the integrity of its distribution system. Operators may not need to consider or perform every step presented. It is not intended that an operator evaluate every option or provide justification or reasons why options were not implemented.

(d) Section 192.1003 exempts master meter systems and individual service lines directly connected to a transmission, gathering, or production pipeline. Most of these types of service lines are commonly known as "farm taps". Farm taps can be excluded from DIMP requirements if they are being maintained in accordance with §192.740(a) and (b).

(e) Section 192.1015 imposes different requirements for small liquefied petroleum gas (LPG) operators (i.e., those serving fewer than 100 customers from a single source). Since these pipeline systems are less complex, the integrity management requirements are simplified. The appropriate portions of this guide material are valid for those operators. PHMSA-OPS has published the following documents to assist operators of small LPG systems to implement requirements of the DIMP rule:

(1) "Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators"
Guidance for Carrying Out Requirements in the Gas Distribution Integrity Management Rule (2013) | PHMSA (dot.gov)).

(2) "Guidance Manual for Operators of Small Natural Gas Systems"
(https://www.phmsa.dot.gov/training/pipeline/guidance-manuals).

(3) "Guidance Manual for Operators of LP Gas Systems"
(https://www.phmsa.dot.gov/training/pipeline/guidance-manuals).

1.2 Glossary of Abbreviations.

Abbreviation	Meaning
A/A	additional or accelerated (actions)
CP	cathodic protection
DIMP	Distribution Integrity Management Program
LPG	liquefied petroleum gas
PE	polyethylene
SCADA	supervisory control and data acquisition
SDR	standard dimension ratio
SME	subject matter expert

1.3 How to use this guide material.

The guide material is organized to coincide with the seven required elements of a DIMP. The order in which the guidance is presented does not imply the order in which it should be applied. However, the operator needs to address each element in some way. Once an operator determines how it can best accomplish distribution system integrity, the guide material may be used to support or direct the operator's

Primary Threat	Threat Subcategories	Questions to Check Subcategory Applicability to System	Extent of Threat		
			General	Local	NA
EXCAVATION DAMAGE (Continued)	Third Party (Continued)	○ Have leaks been experienced on the system where previous damage has occurred ○ Are there known areas of blasting or demolition activity? ○ Have leaks occurred due to blasting? ○ Do portions of the system exist in areas where excavation in the area of the pipeline would require the use of explosives?			
OTHER OUTSIDE FORCE DAMAGE	Vehicular	○ Are aboveground facilities being hit by vehicles? ○ Are aboveground facilities located near a roadway, driveway, or other location where they may be susceptible to vehicular damage? ○ Are susceptible aboveground facilities protected from vehicular damage?			
	Vandalism	○ Has damage or leakage been caused by malicious actions of unauthorized individuals? ○ Has gas theft occurred?			
	Fire/Explosion (primary)	○ Have there been instances of "Fire First" events (the origin of the fire is unrelated to the gas system subject to Parts 191 and 192)?			
	Leakage (previous damage)	○ Have significant numbers of previous damage cases been found? ○ Has leakage caused by previous damage occurred?			
	Blasting	○ Does the potential for blasting operations near gas facilities exist? ○ Are appropriate procedures in place? ○ Has blasting damage occurred?			
	Mechanical damage: > Steel pipe > Plastic pipe > Pipe components	○ Have failures due to mechanical damage been experienced, such as underground structures in contact with facilities?			
MATERIAL OR WELD	Manufacturing defects	○ Have manufacturing defects in pipe or non-pipe components been experienced?			

Table 4.1 Continued

Primary Threat	Threat Subcategories	Questions to Check Subcategory Applicability to System	Extent of Threat		
			General	Local	NA
MATERIAL OR WELD (Continued)	Materials/ Plastic	○ Do any of the following materials exist in the system? > Century Utility Products? > Low-ductile inner wall Aldyl A pipe manufactured by DuPont Company before 1973? > PE 3306?			
	Weld/Joint	○ Have failures in welds or other joints occurred?			
EQUIPMENT FAILURE	System equipment	○ Have failures been experienced due to leaking seals or gaskets? ○ Have regulator or control malfunctions been experienced? ○ Have valve leaks/failures occurred? ○ Have other gas carrying facilities malfunctioned?			
INCORRECT OPERATION	Inadequate procedures	○ Have failures been experienced due to inadequate procedures?			
	Inadequate safety practices	○ Have failures been experienced due to inadequate safety practices?			
	Failure to follow procedures	○ Have failures been experienced due to a failure to follow procedures?			
	Construction/ workmanship defects	○ Have failures been experienced due to workmanship defects?			
OTHER		○ Have failures been experienced due to other reasons?			

TABLE 4.1 - SAMPLE THREAT IDENTIFICATION METHOD

4.4 *Handling Interactive Threats.*
Piping systems may be coincidently subjected to several of the threats defined in Section 4. However, when two or more of the threats combine in such a way that causes an increase in the severity, likelihood, or consequence of a failure, then these are called *Interactive Threats*.

Example 1: An operator estimates a certain type of fitting to fail at a rate of 1 in 1,000 due to "Equipment Defects." However, the operator has determined that the same fittings will fail at a much higher rate, and with a more severe mode of failure when additionally subjected to "Other Outside Forces" (e.g., soil erosion, settling) and much greater consequence.

Example 2: An operator estimates that a known type of material experiences 1 leak per mile due to material degradation. However, the operator has determined that the same material will experience a much higher leakage rate, with a more severe mode of failure, when additionally subjected to "Other Outside Forces" such as the following.
(a) Frost heave.
(b) Settling.

10 REPORT FITTING FAILURES

Except for master meter or small LPG operators, operators are required to report the total number of hazardous leaks caused by mechanical fitting failures on the distribution annual report Form F7100.1-1.

Note: *Hazardous leak and mechanical fitting* are defined in §192.1001.

11 SAMPLE DIMP APPROACHES

11.1 SME approach.

Because this approach relies more on personnel knowledge and experience, operators of smaller, less complex systems may find it more appropriate.

(a) Identify distribution system problems that have occurred and relate these to the eight identified primary threat categories. An operator may choose to break down the primary threat categories into subcategories for more effective understanding and focus.
(b) Use the knowledge and experience of SMEs and other available information to understand the distribution system and its associated operating and maintenance experience.
(c) Use the identified threats and associated consequences, evaluate and rank the involved risks.
(d) If additional or accelerated risk management measures are needed, take reasonable actions to address the targeted risks.
(e) Establish performance measures for key risk management activities and monitor accordingly.
(f) Periodically evaluate performance measure trends and indications. Change program procedures or activities as needed.
(g) Report information as required.

11.2 Mathematical approach.

This approach may require more rigorous segmentation or grouping of specific information. Thus it may be more suited for operators with records and mapping information tracked electronically.

(a) Identify and gather available information about the distribution system and its associated operating and maintenance experience.
(b) Establish criteria for identifying facilities or groups of facilities within the distribution system. Then, using the knowledge and experience of SMEs together with other available information, decide which factors (e.g., pipeline traits, threats, consequences, environments) are associated with each identified facility or group of facilities. An operator may choose to break down the primary threat categories into subcategories for more effective understanding and focus.
(c) Assign weighting values to relevant factors involved and using a mathematical tool, analyze and establish a risk score for each facility or group of facilities. Based on calculated scores and supplemental considerations from SMEs, the facilities or groups of facilities can be ranked accordingly.
(d) For facilities or groups of facilities where further risk reduction is needed, implement activities that the operator believes will best achieve the desired results.
(e) Identify and track performance measures to determine whether the efforts to manage targeted risks are effective.
(f) Periodically evaluate performance measure trends and indications and change program procedures or activities as needed.
(g) Report information as required.

GUIDE MATERIAL APPENDIX G-192-8A

(See §§192.1001, 192.1003, 192.1005, 192.1007, 192.1011, 192.1015, and Guide Material Appendix G-192-8)

DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM (DIMP) CROSS-REFERENCES TO RELEVANT GUIDE MATERIAL

Guide Material Appendix G-192-8, "Distribution Integrity Management Program (DIMP)" contains guide material for complying with the DIMP requirements. It contains Table 4.1 – "Sample Threat Identification Method," which is a table that lists "Primary Threats, Threat Subcategories, and Questions to Check Subcategory Applicability to System." This Guide appendix follows the format of that table and references the other existing guide material sections that may be of assistance in the development of a written integrity management plan.

Primary Threat	Threat Subcategories	Section	Title
ALL	All	603	General provisions
		605	Procedural manual for operations, maintenance, and emergencies
		613	Continuing surveillance
		615	Emergency plans
		616	Public awareness
		617	Investigation of failures
		625	Odorization of gas
		627	Tapping pipelines under pressure
		703	General
		721	Distribution systems: Patrolling
		723	Distribution systems: Leakage surveys
		727	Abandonment or deactivation of facilities
		GMA G-191-3	Distribution System Annual Report
		GMA G-192-11	Gas Leakage Control Guidelines For Natural Gas Systems (Methane)
		GMA G-192-11A	Gas Leakage Control Guidelines For Petroleum Gas Systems
CORROSION FAILURE	External corrosion: bare steel pipe (CP or no CP)	14	Conversion to service subject to this part
		53	General
		452	How does this subpart apply to converted pipelines and regulated onshore gathering lines?
		453	General
		455	External corrosion control: Buried or submerged pipelines installed after July 31, 1971
		457	External corrosion control: Buried or submerged pipelines installed before August 1, 1971
		459	External corrosion control: Examination of buried pipeline when exposed
		461	External corrosion control: Protective coating

Table Continued

GUIDE MATERIAL APPENDIX G-192-11

(See guide material under §§192.3, 192.503, 192.557, 192.615, 192.703, 192.706, 192.723, and 192.941)

GAS LEAKAGE CONTROL GUIDELINES FOR NATURAL GAS SYSTEMS (METHANE)

(See Guide Material Appendix G-192-11A for petroleum gas systems)

1 SCOPE

These guidelines provide criteria for the detection, grading, and control of gas leakage and related records for systems transporting natural gas.

2 GENERAL DISCUSSION

(a) A separate set of guidelines for natural gas system leakage surveys has been developed because of the differing physical properties of petroleum gases and natural gas.
(b) When considering gas leakage detection and control, the two most significant differences between natural gas and petroleum gas vapor are their specific gravities and flammable limits. The specific gravity of natural gas is approximately 0.6 which is, therefore, lighter than air. This .property facilitates the venting and dissipation of natural gas leakage into the atmosphere.
(c) The flammable range of natural gas is approximately 5% to 15% gas in air, compared to approximately 2% to 10% gas in air for petroleum gases.

SIGNIFICANT PHYSICAL PROPERTIES OF NATURAL GAS	
Formula	Mixture
Normal State @ atmospheric pressure @ 60 ºF	Gas
Specific Gravity (Air = 1)	0.6
Flammability Limits	
Lower limit % Gas in Air	5
Upper limit % Gas in Air	15

TABLE 1

3 DEFINITIONS (Applicable to Guide Material Appendix G-192-11 Only)

Barhole is a hole that is made in the soil or paving for the specific purpose of testing the subsurface atmosphere with a CGI.

Barholing means the placement of sample points or test holes.

Building is any structure which is normally or occasionally entered by humans for business, residential or other purposes, and in which gas could accumulate.

Combustible gas indicator (CGI) is a device capable of detecting and measuring gas concentrations (of the gas being transported) in the atmosphere.

Confined space is any subsurface structure (e.g., vaults, tunnels, catch basins, manholes) of sufficient size to accommodate a person, and in which gas could accumulate.

Follow-up inspection is an inspection performed, after a repair has been completed, to determine the effectiveness of the repair.

Gas associated substructure is a device or facility utilized by an operator (e.g., a valve box, vault, test box, vented casing pipe) which is not intended for storing, transmitting or distributing gas.

L.E.L. is the lower explosive limit of the gas being transported.

Natural gas is a mixture of gases that is primarily methane and is lighter than air.

Prompt-action is dispatching qualified personnel without delay for the purpose of evaluating and, where necessary, abating the existing or probable hazard.

Reading is a repeatable deviation on a CGI or equivalent instrument, expressed in LEL. Where the reading is in an unvented confined space, consideration should be given to the rate of dissipation when the space is ventilated, and the rate of accumulation when the space is resealed.

Small substructures (other than gas associated substructures) are any subsurface structures that are of insufficient size to accommodate a person (e.g., telephone and electrical ducts and conduit, non-gas-associated valve and meter boxes), and in which gas could accumulate or migrate.

Tunnel is a subsurface passageway large enough for a person to enter and in which gas could accumulate.

4 LEAKAGE DETECTION

This manual process is usually performed at the time of detection by the person performing the leak detection survey or investigation.

Note: See use of barhole in 5.3(a), (b), and (j)(7) and 5.4(k) below.

4.1 Qualification of personnel.

For leak surveys, use personnel who are qualified (see Subpart N) in the type of survey being performed. These personnel should be familiar with the characteristics of the gas in the system and trained in the use of leak detection instruments.

4.2 Reports from outside sources.

Any notification from an outside source (e.g., police or fire department, other utility, contractor, customer or general public) reporting an odor, leak, explosion or fire, which may involve gas pipelines or other gas facilities, should be investigated promptly. If the investigation reveals a leak, the leak should be graded and action should be taken in accordance with these guidelines.

4.3 Odors or indications from foreign sources.

When leak indications (e.g., gasoline vapors, natural, petroleum, sewer or marsh gas) are found to originate from a foreign source or facility, or customer-owned piping, prompt actions should be taken where necessary to protect life and property. Potentially hazardous leaks should be reported promptly to the operator of the facility, and where appropriate, to the police department, fire department, or other governmental agency. When the operator's pipeline is connected to a foreign facility (e.g., the customer's piping), necessary action should be taken to eliminate the potential hazard, such as disconnecting or shutting off the flow of gas to the facility.

4.4 Leak surveys and test methods.

For leak surveys, see the limitations under §§192.706 and 192.723 regarding leak detection equipment. The following gas leak surveys and test methods may be employed, as applicable, in accordance with written procedures.

- Surface Gas Detection Survey
- Subsurface Gas Detection Survey (including barhole surveys)
- Vegetation Survey
- Pressure Drop Test
- Bubble Leakage Test

Other survey and test methods may be employed if they are deemed appropriate and are conducted in accordance with procedures that have been tested and proven to be at least equal to the methods listed in this section.

(a) Surface Gas Detection Survey.

(1) *Definition*. A continuous sampling of the atmosphere at or near ground level for buried gas facilities and adjacent to above-ground gas facilities with a gas detector system capable of

detecting a concentration of 50 ppm gas in air.

(2) *Procedure*. Equipment used to perform these surveys may be portable or mobile. For buried piping, sampling of the atmosphere should, where practical, take place as close to ground surface as permitted by gas detector design, due to the potential for rapid diffusion of leaking gas to the atmosphere. In areas where the piping is under pavement, samplings should also be at curb line(s), available ground surface openings (e.g., manholes, catch basins, sewer, power, and telephone duct openings, fire and traffic signal boxes, cracks in the pavement or sidewalk) or other interfaces where the venting of gas is likely to occur. For exposed piping, sampling should be adjacent to the piping.

(3) Utilization. The survey should be conducted at speeds slow enough to allow an adequate sample to be continuously obtained by placement of equipment intakes over the most logical venting locations, giving consideration to the location of gas facilities. Gas detector design or adverse conditions may limit the use of this survey method. Operators should consult with manufacturers for equipment restrictions or limitations. Some adverse conditions that may affect the venting of subsurface gas leaks are:

(i) Moisture. A high water table, tidal effects, or excessive moisture from rain may inhibit venting of the gas to atmosphere.

(ii) Frost. Where frost is present in the soil, leak diffusion patterns may change.

(iii) Ice and Snow Cover. Ice and snow cover may cause surface sealing, limiting the venting of gas to the atmosphere.

(iv) Wind. High or gusting winds may alter diffusion at the surface of the ground.

(b) Subsurface Gas Detection Survey.

(1) *Definition*. The sampling of the subsurface atmosphere with a combustible gas indicator (CGI) or other device capable of detecting 0.5% gas in air (10% of the LEL) at the sample point.

(2) *Procedure*.

(i) The survey should be conducted by performing tests with a CGI in a series of available openings (confined spaces and small substructures) or barholes over, or adjacent to, the gas facility or both. The location of the gas facility and its proximity to buildings and other structures should be considered in the spacing of the sample points. Sampling points should be as close as possible to the main or pipeline, and never further than 15 feet laterally from the facility. Along the route of the main or pipeline, sampling points should be placed at half the distance between the pipeline and the nearest building wall, or at 30 feet, whichever is shorter, but, in no case need the spacing be less than 10 feet. The sampling pattern should include sample points adjacent to service taps, street intersections, and known branch connections, as well as over or adjacent to buried service lines at the building wall.

(ii) Underground conduit and sewer structures can provide unobstructed and interconnected (or exclusive) migration paths toward buildings. If readings are found in these structures, further investigation should follow. See 5.3(j) below.

(3) *Utilization.*

(i) Good judgment should be used to determine when available openings (e.g., manholes, vaults, valve boxes) are sufficient in number to provide an adequate survey. If necessary, additional sample points (barholes) should be made.

(ii) Sampling points should be of sufficient depth to directly sample within the subsurface or substructure atmosphere and not be restricted by capping obstructions, such as paving, concrete, soil moisture or frost or surface sealing by ice or water.

(4) *Precaution*. When placing barholes for testing, consideration should be given to barhole placement and depth to minimize the potential for damage to other underground facilities and possible injury to personnel conducting the investigation. (See 5.2(d) and 5.3 below.)

(c) Vegetation Survey.
  (1) *Definition*. Visual observations made to detect abnormal or unusual indications in vegetation.
  (2) *Procedure*. All visual indications should be evaluated using a CGI. Personnel performing these surveys should have good all-around visibility of the area being surveyed and their speed of travel should be determined by taking into consideration the following.
    (i) System layout.
    (ii) Amount and type of vegetation.
    (iii) Visibility conditions, such as lighting, reflected light, distortions, terrain or obstructions.
  (3) *Utilization.*
    (i) This survey method should be limited to areas where adequate vegetation growth is firmly established.
    (ii) This survey should not be conducted under the following conditions.
      (A) When soil moisture content is abnormally high.
      (B) When vegetation is dormant.
      (C) When vegetation is in an accelerated growth period, such as in early spring.
    (iii) Other acceptable survey methods should be used for locations within a vegetation survey area where vegetation is not adequate to indicate the presence of leakage.
    (iv) Vegetation surveys may also be employed to supplement surface and subsurface gas detection surveys utilizing appropriate leak detection equipment.

(d) Pressure Drop Test.
  (1) *Definition*. A test to determine if an isolated segment of pipeline loses pressure due to leakage.
  (2) *Procedure*. Facilities selected for pressure drop tests should first be isolated and then tested. The following criteria should be considered in determining test parameters.
    (i) Test Pressure. The pressure used to perform a pressure drop test on existing facilities solely for the purpose of detecting leakage should be at least equal to the operating pressure. A pressure test conducted for the purpose of line qualification or uprating must be performed in accordance with the requirements of Subparts J or K.
    (ii) Test Medium. The test medium used must comply with the requirements of §192.503(b).
    (iii) Test Duration. The duration of the test should be of sufficient length to detect leakage. The following should be considered in the determination of the duration.
      (A) The volume under test.
      (B) The time required for the test medium to become temperature stabilized.
      (C) The sensitivity of the test instrument.
  (3) *Utilization*. Pressure drop tests should be used only to establish the presence or absence of a leak on a specifically isolated segment of a pipeline. Normally, this type of test will not provide a leak location. Therefore, facilities on which leakage is indicated may require further evaluation by another detection method in order that the leak may be located, evaluated, and graded.

(e) Bubble Leakage Test.
  (1) *Definition*. The application of a soap-water or other foam forming solutions on exposed piping to determine the existence of a leak.
  (2) *Procedure*. The exposed piping systems should be reasonably cleaned and completely coated with the solution. Leak detection solution should not be harmful to gas piping. Leaks are indicated by the presence of bubbles.
  (3) *Utilization*. This test method may be used for the following.
    (i) Testing exposed aboveground portions of a system, such as meter set assemblies or exposed piping on bridge crossings.
    (ii) Testing a tie-in joint or leak repair, which is not included in a pressure test.

4.5 Selecting an instrument for the detection of gas.

(a) Operators should consider the following when selecting a detection instrument.
   (1) Usage.
      (i) Leak survey.
      (ii) Leak investigation (first response).
      (iii) Leak classification (barholing).
      (iv) Pinpointing.
   (2) Application.
      (i) Distribution system leak survey.
      (ii) Transmission line leak survey.
      (iii) Emergency response.
      (iv) Pinpointing.
   (3) Limitations.
      (i) Sensitivity.
      (ii) Type of sample system.
      (iii) Weather related issues, such as wind, moisture, frost, snow, and ice.
      (iv) Any condition that may limit detection capability of instrument.

(b) See Table 2 for a listing of available technologies.

4.6 Maintenance of instruments.

Each instrument used for leak detection and evaluation should be operated in accordance with the manufacturer's recommended operating instructions and:

(a) Should be periodically "checked" while in use to ensure that the recommended voltage requirements are available.
(b) Should be tested daily or prior to use to ensure proper operation, to ensure that the sampling system is free of leakage, and to ensure that the filters are not obstructing the sample flow.
(c) Any instrument used for leak survey should be tested for operation at each start-up and periodically tested during a survey.

4.7 Calibration of instruments.

Each instrument used for leak detection and evaluation should be calibrated at the following times in accordance with the manufacturer’s recommended calibration instructions.

(a) After any repair or replacement of parts.
(b) On a regular schedule giving consideration to the type and usage of the instrument involved. HFI systems and CGI instruments should be checked for calibration at least once each month while in use.
(c) At any time it is suspected that the instrument’s calibration has changed.

5 LEAK INVESTIGATION AND CLASSIFICATION

5.1 Scope.

(a) Leak investigation and leak classification provide a means for determining the location, extent, and potential hazard of migrating gas. A leak investigation should be initiated to address a report of a possible leak indication. Prompt action should be taken as necessary for protection of people first and then property. Leak indications may include the following.
   (1) Odor complaints.
   (2) Reports of dead or discolored vegetation.
   (3) Positive readings from leak detection equipment.
(b) Leak indications may originate from the following.
   (1) Scheduled leak surveys.
   (2) Line patrols.
   (3) Customer reports.
   (4) Reports from the general public.

(c) Regardless of their origin, leak indications should be investigated promptly to identify any hazardous condition.
(d) In any leak investigation, an operator should presume that a Grade 1 or hazardous leak might exist.
(e) Only after completing the leak investigation should an operator determine an appropriate leak classification. Leak indications may be from sources other than natural gas.

5.2 Procedural Guidance – General.

(a) The following guide material is not intended to be step by step procedure in responding to leak calls but is intended to assist operators in developing their own written procedures. Certain actions may be initiated ahead of other action items based on conditions at the leak location.
(b) There are situations that warrant entering a building before checking the extent of gas migration. These situations might include the following.
  (1) Broken main, service line, or customer owned fuel line.
  (2) Gas blowing out of the ground.
  (3) Hissing, roaring, or other sounds indicating gas leakage.
  (4) Noticeable odor levels upon entry of a building.
  (5) Noticeable odor levels outside a building.
  (6) Gas in multiple underground structures that are normally connected by ducts or piping to houses, especially when the gas readings are high.
  (7) Inside odor reports in an area of underground leakage or coincident with outside odor reports.
  Note: *If a gas reading at or above hazardous concentration level or an operator established criteria is detected, the operator should consider evacuating the structure. Calling for additional resources might be necessary based on the type of building involved in the leak call (e.g., hospital, school, commercial building). The operator should also consider shutting down the gas supply upstream of the identified leak location to stop the flow of gas into the ground where an underground gas migration may cause an imminent safety threat.*
(c) Where a leak indication appears to originate from buried piping, operator personnel should identify the extent of gas migration. If the migration pattern extends to nearby structures, the structures should be immediately checked for the presence of combustible gases. Structures may include buildings, confined spaces, and other buried utilities. Considerations should include the following.
  (1) Based on the local conditions, structures beyond the identified migration pattern may also need to be checked.
  (2) The levels of gas migrating into buildings need to be monitored so that the "make safe" actions can be initiated at appropriate times. Under these and similar conditions, it is recommended that immediate assistance be requested and the inside investigations be initiated without delay, including finding the farthest extent of gas migration.
  (3) Because leakage can be dynamic, the gas levels in nearby buildings need to be continually monitored. It is not uncommon, under extreme conditions, for buildings that had no gas detected during the initial check to have gas levels found upon subsequent checks.
  (4) Re-entry, by qualified personnel, to any structure within the boundaries of gas migration should be performed with extreme caution.
(d) Personnel investigating a leak indication reported as either an "inside" or "outside" call should perform a visual check for the existence of other underground utilities in the area. Examples of other underground facilities in the area of suspected gas migration include the following.
  (1) Customer-owned service lines.
  (2) Buried fuel lines.
  (3) Electric lines.
  (4) Telephone wiring.
  (5) Television cables.
  (6) Water or sewer lines.
(e) Consider the potential for gas migration under fully paved areas, ground frost, or buildings.
(f) Barholing should be part of a leak investigation. See 5.3 below for guidelines for barholing.
(g) If the leak investigation is initiated by an outside odor compliant, see 5.3 below.
(h) If the leak investigation is initiated by an inside odor compliant, see 5.4 below.

5.3 Procedural Guidance – Outside underground leak.

(a) Using a barhole device and CGI, the operator should barhole in the area of indication along and adjacent to operator's mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, risers, or service entry points to buildings. If there is an outside meter in the suspected leakage area, the operator should attempt to barhole between the service riser and the foundational wall. If there is an inside meter, the operator should attempt to barhole near the suspected location of service entry point at the foundational wall. Look for previous markouts or other indicators that might identify the point of entry. If a hazardous condition is detected or discovered during a leak investigation, see 5.2(b) above.
Note: If the leakage pattern extends outside the wall of a structure, the leakage investigation should continue to the inside of the structure.

(b) Use caution when barholing to avoid damage to operator facilities or other underground structures. The operator should attempt to identify, where practicable, other underground facilities and avoid barholing directly over operator piping, customer-owned piping, and identified or suspected underground facilities.

(c) Barholing of an underground leak indication should be done in a uniform manner by pushing or manually driving the barhole in the soil. Barholes should be placed to a uniform depth and distance to adequately define the leak area. Operators might consider establishing a maximum barhole depth based on the depth of the operator and other facilities. However, under certain soil and environmental conditions (e.g., clay type soils, frost conditions), it may be necessary to barhole deeper than the established recommended maximum barhole depth. Once the area of the leak indication is determined, the operator should barhole and sample with the CGI in all directions from the approximate center of the leak until zero-gas readings are detected.

(d) If a meter set is outside, observe its dial for unusual flow.

(e) Look for indications of construction activity, which might have caused damage to the operator's facilities. Examples are:
  (1) Excavation.
  (2) Pavement patches.
  (3) Landscaping.
  (4) Fencing installation.
  (5) Directional drilling or boring activity.
  (6) Settling or subsidence.

(f) Look for building additions that may have been constructed over natural gas service lines.

(g) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak.

(h) Check available openings in the area of a leak indication. These openings may include the following.
  (1) Valve boxes.
  (2) Catch basins.
  (3) Manholes.
  (4) Vaults.
  (5) Water meter boxes.
  (6) Pits.
  (7) Underground irrigation control boxes.
  (8) Other openings that allow access to underground atmospheres.

(i) Check for migration along other buried utilities that may serve as a path for leaking gas. Paths for leaking gas might include the following.
  (1) Sanitary sewer systems.
  (2) Drains and drainage systems.
  (3) Water mains and service lines.
  (4) Telephone lines.
  (5) Electric lines.
  (6) Cable TV lines.

(j) Investigating readings in underground conduit structures.
  (1) Underground conduits (e.g., electric, telephone, cable) or sewer and drain structures (e.g., storm, sanitary, catch basins, vent boxes) can provide unobstructed and interconnected (or exclusive) migration paths for gas. Therefore, if readings are found in these types of structures, the operator should conduct successive checks of all interconnecting manholes until zero readings are found.
  (2) Buildings should also be checked to determine if interconnecting conduits are entering buildings and possibly providing migration of gas to the inside of the building. The investigation may require coverage of numerous blocks and buildings to achieve proper results.
  (3) To determine which manholes are "interconnected," an operator can perform a survey of available openings, noting similarly identified manhole covers. Other techniques include the following.
    (i) Contact and work with the owner-utility directly, or through one-call (observing local one-call laws).
    (ii) Pull the manhole covers and observe (from the surface) the apparent directions of the conduits.
    Note: Rectangular lids are common in the electrical industry. Opening this style of lid can cause damage if the lid drops through the opening. Use extreme caution when opening these lids or ask the owner-utility for assistance.
  (4) After identifying all successive manholes with positive readings and the clear manholes at the ends, all gas facilities between the clear manholes should be considered to be within the area of migration and should be investigated.
  (5) Due to prevailing air flow within conduit systems, it is not unusual for gas leaks to be closer to manholes with zero readings than those with positive readings.
  (6) Ventilate all manholes. This should reduce readings in manholes that are farther from the leak source.
  Note: This action can change the pattern of air flow within the conduit system and change readings inside buildings (if conduits connect to the adjacent buildings). Therefore, check buildings as discussed in 5.3(i)(2) above to determine if this should be a concern.
  (7) Continue to pinpoint (see 7 below) the leak by barholing as described in the beginning of this section (5.3). If necessary, barhole over or near the conduit to obtain a lead to the source leak. Be cautious of other owner-utilities as discussed in 7.3(a).
(k) If a leak area involves multiple buildings, the leak investigation area should be expanded to include each building in the affected area. Consider extending the leak investigation area one or two buildings, or a specified distance, beyond the leak migration area.
(l) If a leak is detected on aboveground exposed piping, perform a bubble test using a leak detection solution to determine the magnitude of the leak. See 4.4(e) above.
(m) Based on the leak location, extent of migration, and leak magnitude, assign a leak classification to the leak area. See Tables 3a, 3b, and 3c.

5.4 Procedural Guidance – Inside leak or odor complaint.
(a) It may be necessary to investigate a reported leak or gas odor inside a structure. These investigations may result from the following.
  (1) Gas migration.
  (2) Indications of gas readings inside a building while performing routine leak surveys.
  (3) Odor complaints.
  Note: *If a hazardous condition is detected or discovered during a leak investigation, see 5.2(b) above.*
(b) Leaks may originate on customer-owned piping or equipment.
(c) Look for indications of construction activity, which might have caused damage to the operator's facilities. Examples are:
  (1) Excavation.
  (2) Pavement patches.
  (3) Landscaping.
  (4) Fencing installation.

(5) Directional drilling or boring activity.
(6) Settling or subsidence.

(d) Look for building additions that may have been constructed over natural gas service lines.
(e) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak. See 5.3 above.
(f) The CGI and an approved flashlight should be turned on prior to entering any building or structure.
(g) If there is an outside meter set, observe its dial for excessive flow or movement.
(h) Using a CGI, test around the entry door for gas indications. Do not ring the doorbell; knock on the door to get the attention of occupants. Upon entry do not operate any lights, but do take appropriate precautions to prevent accidental ignition. Immediately sample the inside atmosphere for the presence of a combustible gas. Natural gas is lighter than air and will accumulate near ceilings or in higher floors. Petroleum gas is heavier than air and will accumulate in the low atmosphere. If a gas reading at or above a hazardous concentration or an operator-established criteria is detected, the operator should consider evacuating the structure. Calling for additional resources might be necessary based on the type of building involved in the leak call (e.g., hospital, school, commercial building).
Note: *If gas is detected, the applicable portions of the operator's emergency procedures need to be implemented* (§192.615(a)(3)).
(i) If the call is an odor complaint, proceed to the area indicated by the caller/occupant to investigate. When entering a building as a result of detecting a leak on outside underground piping, initiate an "inside" investigation. If the visit is in response to an odor complaint, attempt to locate and identify all gas lines associated with the building to their respective points of termination or equipment connection. Observe for abandoned or inactive natural gas lines, and natural gas lines that may exist under a portion of the structure that has no basement (e.g., an addition, garage).
(j) If the building has a basement, enter it while constantly sampling with a CGI. Proceed to check the following with the CGI.
(1) Basement wall that is adjacent to the outside leak area for migration of gas.
(2) Gas piping that passes through basement walls.
(3) Cracks in basement walls.
(4) Other utility entry points, floor drains, laundry sink drains, bathroom drains, and toilets for the presence of combustible gases.
(5) Basement walls adjacent to buried gas piping.

(k) If the structure has no basement, but has a crawlspace, attempt to gain access to the crawlspace and sample its atmosphere for the presence of combustible gases. If the structure is built on a concrete slab, check all utility penetration points for gas indications. Attempt to barhole at an angle under the concrete slab along the leak area and near utility entrances for gas indications.
(l) Use the CGI and a leak detection solution to locate the source of the gas odor, and to identify the degree of potential hazard.
(m) Using a barhole device and CGI, the operator should barhole in the area of indication along and adjacent to operator's mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, risers, or service entry points to buildings. If there is an outside meter in the suspected leakage area, the operator should attempt to barhole between the service riser and the foundational wall. Look for previous markouts or other indicators that might identify the point of entry.
Note: If the leakage pattern extends to the outside wall of a structure, the leak investigation should continue to the inside of the structure.
(1) Use caution when barholing to avoid damages to operator facilities or other underground structures. The operator should attempt to identify, where practicable, other underground facilities and avoid barholing directly over operator piping, customer-owned piping, and other identified suspected underground facilities.
(2) Barholing of an underground leak indication should be done in a uniform manner by pushing or manually driving the barhole device into the soil. Barholes should be placed to a uniform depth and distance to adequately define the leak area. Operators might consider establishing a recommended maximum barhole depth based upon the depth of the operator facilities. However, under certain soil and environmental conditions (e.g., clay-type soils, frost

conditions), it might be necessary to barhole deeper than the established recommended maximum barhole depth. Once the area of leak indication is determined, the operator should barhole and sample with a CGI in all directions from the approximate center of the leak until zero-gas readings are detected.

(n) The operator should consider leak testing accessible gas piping, including abandoned or inactive lines, using a CGI or leak detection solution.

(o) Where an operator's written procedures do not require an instrument leak test of customer-owned piping, consider performing a pressure-drop test or a meter dial test.

5.5 Leak grades.

Based on an evaluation of the location or magnitude of a leak or both, one of the following leak grades should be assigned, thereby establishing the leak repair priority.

(a) *Grade 1*, a leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. See §192.703(c).

(b) *Grade 2*, a leak that is recognized as being non-hazardous at the time of detection, but, requires scheduled repair based on probable future hazard.

(c) *Grade 3*, a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

5.6 Leak classification and action criteria.

Guidelines for leak classification and leakage control are provided in Tables 3a, 3b, and 3c. The examples of leak conditions provided in the tables are presented as guidelines and are not exclusive. The judgment of the operator personnel at the scene is of primary importance in determining the grade assigned to a leak.

5.7 Temporary mitigative measures for Grade 1 leaks.

Note: See GMA G-192-8 for additional information on leak classification and reinspection guidelines.

(a) Temporary mitigative measures (e.g., venting, shutting down the line, reducing pressure, installing a temporary leak clamp) might be necessary to control the hazard of a leak until a permanent repair can be made.

(b) A frequency of inspection should be established to verify that these measures are effectively mitigating the hazard until the leak is repaired.

(c) If it is not feasible to make a permanent repair at the time of discovery, then a permanent repair should be made as soon as practicable.

5.8 Follow-up inspection.

The adequacy of leak repairs should be checked before backfilling. The perimeter of the leak area should be checked with a CGI. Where there is residual gas in the ground after the repair of a Grade 1 leak, follow-up inspections should be made as soon as practical after allowing the soil atmosphere to vent and stabilize, but, in no case later than one month following the repair. In the case of other leak repairs, the need for a follow-up inspection should be determined by qualified personnel.

5.9 Reevaluation of a leak.

When a leak is to be reevaluated (see Tables 3b and 3c), it should be classified using the same criteria as when the leak was first discovered.

6 RECORDS AND SELF-AUDIT GUIDELINES

6.1 Leak records.

Historical gas leak records should be maintained. Sufficient data should be available to provide the information needed to complete the Department of Transportation Leak Report Forms DOT F-7100.1, DOT F-7100.1-1, DOT F-7100.2 and DOT F-7100.2-1, and to demonstrate the adequacy of operator's maintenance programs.

The following data should be recorded and maintained, but need not be in any specific format or retained at one location. Time of day and environmental description records are required only for those leaks that are reported by an outside source or require reporting to a regulatory agency.

(a) Date discovered, time reported, time dispatched, time investigated and by whom.
(b) Date(s) reevaluated before repair and by whom.
(c) Date repaired, time repaired and by whom.
(d) Date(s) rechecked after repair and by whom.
(e) If a reportable leak, date and time of telephone report to regulatory authority and by whom.
(f) Location of leak.
(g) Leak grade.
(h) Line use (distribution, transmission, etc.).
(i) Method of leak detection (if reported by outside party, list name and address).
(j) Part of system where leak occurred (main, service line, etc.).
(k) Part of system that leaked (pipe, valve, fitting, compressor or regulator station, etc.).
(l) Material which leaked (steel, plastic, cast iron, etc.).
(m) Origin of leak.
(n) Pipe description.
(o) Type repair.
(p) Leak cause.
(q) Date pipe installed (if known).
(r) Under cathodic protection? (Yes — No).
(s) Magnitude of CGI indication.

6.2 *Leak survey records.*

For the current and immediately previous survey of an area, the following information should be available.

(a) Description of system and area surveyed. (This could include maps or leak survey logs or both.)
(b) Survey results.
(c) Survey method.
(d) Names of those making survey.
(e) Survey dates.
(f) In addition to the above, the following records should be kept for a pressure drop test.
    (1) The name of the operator, the name of the operator's employee responsible for making the test, and the name of any test company used.
    (2) Test medium used.
    (3) Test pressure.
    (4) Test duration.
    (5) Pressure recording charts, or other record of pressure readings.
    (6) Test results.

6.3 *Self audits*.

In order that the completeness and effectiveness of the leak detection and repair program may be evaluated, self-audits should be performed on the following.

(a) Schedule of leak survey. The operator should ensure that the schedule is commensurate with Subpart M, and the general condition of the pipeline system.
(b) Survey completeness. The operator should ensure that records, such as maps, provided to the leak surveyor are sufficiently complete to meet the leak survey requirements. The following are examples that may be considered when evaluating survey completeness.
    (1) Tagging (e.g., using a two-part numbered tag) will help document completion of the leak survey in a given area.
        (i) Place tags on selected meter sets in the survey area ahead of the scheduled leak survey.
        (ii) Meter tags should be dated when placed.
        (iii) Survey technicians should then be required to return collected tags at the conclusion of the survey day.
    (2) GPS tracking. Real-time GPS tracking of leak survey progress and completion can be plotted on system maps.
(c) Survey effectiveness. The operator should evaluate leak survey results to ensure that, throughout

GUIDE MATERIAL APPENDIX G-192-11A

(See guide material under §§192.3, 192.11, 192.503 192.557, 192.615, 192.703, and 192.723)

GAS LEAKAGE CONTROL GUIDELINES FOR PETROLEUM GAS SYSTEMS

(See Guide Material Appendix G-192-11 for natural gas systems)

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GUIDE MATERIAL APPENDIX G-192-11A

(See guide material under §§192.3, 192.11, 192.503, 192.557, 192.615, 192.703, and 192.723)

GAS LEAKAGE CONTROL GUIDELINES FOR PETROLEUM GAS SYSTEMS

(See Guide Material Appendix G-192-11 for natural gas systems)

1 SCOPE

These guidelines provide criteria for the detection, grading, and control of gas leakage and for related records for systems transporting petroleum gases or petroleum gas/air mixtures that are heavier than air.

2 GENERAL DISCUSSION

(a) A separate set of guidelines for petroleum gas system leakage surveys has been developed because of the differing physical properties of natural gas and petroleum gases.

(b) When considering gas leakage detection and control, the two most significant differences between natural gas and petroleum gas vapor are their specific gravities and flammable limits. Petroleum gas vapor has a specific gravity range of 1.6 to 2.0 that is heavier than air. Therefore, when petroleum gas vapor escapes, it tends to settle in low places, and to move along the bottom of ditch lines and substructures unless dissipated by substantial air movement. It does not readily vent to the surface under normal conditions. When conducting tests for leakage on buried petroleum gas systems, it is essential that samples be taken at or near the pipe, in the bottom of ditch lines and at the low point of substructures.

(c) Hazardous concentrations of petroleum gas can develop rapidly because of the relatively low LEL. The flammable range of natural gas is approximately 5% to 15% gas in air compared to approximately 2% to 10% gas in air for petroleum gases. Therefore, when conducting a petroleum gas system leak survey, it is essential to remember that the lower explosive limit can be as low as 1.9% gas in air. It is essential that Combustible Gas Indicator (CGI) instruments used to conduct petroleum gas leak surveys be properly calibrated. CGI instruments are discussed in more detail in 4.5, 4.6, and 4.7 below.

SIGNIFICANT PHYSICAL PROPERTIES OF FOUR TYPICAL HYDROCARBON GASES NORMALLY FOUND IN DISTRIBUTION AND PIPE LINE SYSTEMS (See Note 1)

	Natural Gas	Propane	Propane / Air 40/60 Percent	Butane
Formula	Mixture	C_3H_8	C_3H_8 / Air	C_4H_{10}
Normal State @ atmospheric pressure @ 60 °F	Gas	Gas	Gas	Gas
Specific Gravity (Air = 1)	0.6	1.6	1.2	2.0
Flammability Limits				
Lower Limit Percent Gas in Air	5	2	See Note 2	2
Upper Limit Percent Gas in Air	15	10	See Note 2	9

Notes:
1 Other mixtures may have significantly different physical properties. Each operator should evaluate the gas in his distribution system and react accordingly.
2 The explosive limits refer to percent gas in air and are the same shown for propane.

TABLE 1

3 DEFINITIONS (Applicable to Guide Material Appendix G-192-11A Only)

Barhole is a hole that is made in the soil or paving for the specific purpose of testing the subsurface atmosphere with a CGI.

Building is any structure which is normally or occasionally entered by humans for business, residential or other purposes, and in which gas could accumulate.

Combustible gas indicator (CGI) is a device capable of detecting and measuring gas concentrations (of the gas being transported) in the atmosphere.

Confined space is any subsurface structure (e.g., vaults, tunnels, catch basin, manholes) of sufficient size to accommodate a person, and in which gas could accumulate.

Follow-up inspection is an inspection performed, after a repair has been completed, to determine the effectiveness of the repair.

Gas associated substructure is a device or facility utilized by an operator (e.g., a valve box, vault, test box, vented casing pipe) that is not intended for storing, transmitting or distributing gas.

L.E.L. is the *lower* explosive limit of the gas being transported.

Natural gas is a mixture of gases that is primarily methane and is lighter than air.

Permanent test point is a selected sample point that has been installed to maintain an opening for the testing of the subsurface atmosphere over or adjacent to the gas facility. Curb boxes, vents, or test inserts are normally used for this purpose.

Prompt-action is dispatching qualified personnel without delay for the purpose of evaluating and, where necessary, abating the existing or probable hazard.

Reading is a repeatable deviation on a CGI or equivalent instrument, expressed in LEL. Where the reading is in an unvented confined space, consideration should be given to the rate of dissipation when the space is ventilated, and the rate of accumulation when the space is resealed.

Small substructures (other than gas associated substructures) are any subsurface structures that are of insufficient size to accommodate a person (e.g., telephone and electrical ducts and conduit, non-gas-associated valve and meter boxes), and in which gas could accumulate or migrate.

Tunnel is a subsurface passageway large enough for a person to enter and in which gas could accumulate.

4 LEAKAGE DETECTION

4.1 Qualification of personnel.

For leak surveys, use personnel who are qualified (see Subpart N) in the type of survey being performed. These personnel should be familiar with the characteristics of the petroleum gas in the system and trained in the use of leak detection instruments.

4.2 Reports from outside sources.

Any notification from an outside source (e.g., police or fire department, other utility, contractor, customer or general public) reporting an odor, leak, explosion or fire, which may involve gas pipelines or other gas facilities, should be investigated promptly. If the investigation reveals a leak, the leak should be graded and action should be taken in accordance with these guidelines.

4.3 Odors or indications from foreign sources.

When leak indications (e.g., gasoline vapors, natural, petroleum, sewer or marsh gas) are found to originate from a foreign source or facility, or customer-owned piping, prompt actions should be taken where necessary to protect life and property. Potentially hazardous leaks should be reported promptly to the operator of the facility and, where appropriate, to the police department, fire department, or other governmental agency. When the operator's pipeline is connected to a foreign facility (e.g., the customer's piping) necessary action should be taken to eliminate the potential hazard, such as disconnecting or shutting off the flow of gas to the facility.

4.4 Leak surveys and test methods.

For leak surveys, see the limitations under §§192.706 and 192.723 regarding leak detection equipment. The following gas leak surveys and test methods may be employed, as applicable, in accordance with written procedures.

— Subsurface Gas Detection Survey (including barhole surveys)
— Pressure Drop Test
— Bubble Leakage Test

Other survey and test methods may be employed if they are deemed appropriate and are conducted in accordance with procedures that have been tested and proven to be at least equal to the methods listed in this section.

The Surface Gas Detection Survey and Vegetation Survey methods used for natural gas systems are not recommended for use on petroleum gas systems. Petroleum gases are heavier than air and will frequently not come to the ground surface or cause surface indications in the vegetation. However, the Surface Gas Detection Survey, when properly conducted by taking into account that the gas is heavier than air, may be used adjacent to above ground facilities.

(a) Subsurface Gas Detection Survey.
   (1) *Definition*. The sampling of the subsurface atmosphere with a combustible gas indicator (CGI) or other device capable of detecting 0.2% gas in air (10% of the LEL) at the sample point.
   (2) *Procedural Guidance*.
      (i) The survey should be conducted by performing tests with a CGI in a series of available openings (confined spaces and small substructures) or barholes immediately adjacent to the gas facility. The following should be considered when selecting the placement of barholes and sample points.
         (A) The location of the gas pipelines and proximity to buildings or other structures.
         (B) Approximate depth of buried gas piping.
         (C) Extent of pavement.
         (D) Soil type and moisture content.
         (E) Available subsurface openings (e.g., valve boxes, catch basins, manholes).
         (F) Underground conduit and sewer structures can provide unobstructed and .... interconnected (or exclusive) migration paths toward buildings. If readings are found in these structures, further investigation should follow. See 5.3(i) below.

      Barhole sample points should be placed along or adjacent to the pipeline, to the approximate depth of the pipeline, and at intervals of 20 feet or less. The sampling pattern should include tests at the building wall at the service riser or point of service line entrance. Consideration should be given to threaded or mechanical joints that have had a history of leakage. Available subsurface openings adjacent to the pipeline should be tested. Where the piping system passes under pavement for a distance of 20 feet or less, barholes should be made at the point of entrance and exit of the paved area. Where the paved area over the pipeline is 20 feet or greater in length, sample points should be located at intervals of 20 feet or less. In the case of extensive pavement, permanent sample points should be considered.

(ii) When testing available openings for petroleum gas, readings should be taken at both the top and bottom of the structure. When testing larger confined spaces or basements, the floor areas, including floor drains, should be thoroughly tested because petroleum gases can lie temporarily in pockets containing explosive mixtures. Since migrating gas may not enter at the pipeline entrance, a perimeter survey of the floors and walls is recommended. When conducting the survey, all barholes should penetrate to the pipe depth, where necessary, in order to obtain consistent and worthwhile readings. This includes penetrating through capping materials such as paving, concrete, frost, or surface sealing by ice or water. The required depth of the barhole will also depend upon the soil conditions, the depth of and pressure in the pipeline, and the type of instrument being used. The readings should be taken at the bottom of the bar. The probe used should be equipped with a device to preclude the drawing in of liquids. When conducting the survey, the inspector should use the most sensitive scale on the instrument, watching for small indications of combustible gas. Any indication should be further investigated to determine the source of the gas. Care should be taken to avoid damaging the pipe or coating with the probe bar.

(3) *Utilization*. This survey method should be utilized for buried facilities. Good judgment should be used to determine when the recommended spacing of sample points is inadequate. Additional sample points should be provided under these conditions. Available openings (e.g., manholes, vaults, valve boxes) should be tested. However, they should not be relied upon as the only points used to test for petroleum gas leakage.

(4) *Precaution*. When placing barholes for testing, consideration should be given to barhole placement and depth to minimize the potential for damage to other underground facilities and possible injury to personnel conducting the investigation. (See 5.2(e) and 5.3 below.)

(b) Pressure Drop Test.

(1) *Definition*. A test to determine if an isolated segment of pipeline loses pressure due to leakage.

(2) *Procedure*. Facilities selected for pressure drop tests should first be isolated and then tested. The following criteria should be considered in determining test parameters.

(i) Test Pressure. The pressure used to perform a pressure drop test on existing facilities solely for the purpose of detecting leakage should be at least equal to the operating pressure. A pressure test conducted for the purpose of line qualification or uprating must be performed in accordance with the requirements of Subparts J or K.

(ii) Test Medium. The test medium used must comply with the requirements of §192.503(b).

(iii) Test Duration. The duration of the test should be of sufficient length to detect leakage. The following should be considered in the determination of the duration.

(A) The volume under test.

(B) The time required for the test medium to become temperature stabilized.

(C) The sensitivity of the test instrument.

(3) *Utilization*. Pressure drop tests should be used only to establish the presence or absence of a leak on a specifically isolated segment of a pipeline. Normally, this type of test will not provide a leak location. Therefore, facilities on which leakage is indicated may require further evaluation by another detection method in order that the leak may be located, evaluated, and graded.

(c) Bubble Leakage Test.

(1) *Definition*. The application of a soap-water or other foam-forming solutions on exposed piping to determine the existence of a leak.

(2) *Procedural Guidance*. The exposed piping systems should be reasonably cleaned and completely coated with the solution. Leak detection solution should not be harmful to gas piping. Leaks are indicated by the presence of bubbles.

(3) *Utilization*. This test method may be used for the following.

(i) Testing exposed aboveground portions of a system, such as meter set assemblies or exposed piping on bridge crossings.

(ii) Testing a tie-in joint or leak repair that is not included in a pressure test.

4.5 Selecting an instrument for the detection of gas.

(a) Operators should consider the following when selecting a detection instrument.
  (1) Usage.
    (i) Leak survey.
    (ii) Leak investigation (first response).
    (iii) Leak classification (barholing).
    (iv) Pinpointing.
  (2) Application.
    (i) Distribution system leak survey.
    (ii) Transmission line leak survey.
    (iii) Emergency response.
    (iv) Pinpointing.
  (3) Limitations.
    (i) Sensitivity.
    (ii) Type of sample system.
    (iii) Weather related issues, such as wind, moisture, frost, snow, and ice.
    (iv) Any condition that may limit detection capability of instrument.

(b) See Table 2 for a listing of available technologies.

4.6 Maintenance of instruments.

Each instrument used for leak detection and evaluation should be operated in accordance with the manufacturer's recommended operating instructions and:

(a) Should be periodically "checked" while in use to ensure that the recommended voltage requirements are available.
(b) Should be tested daily or prior to use to ensure proper operation, to ensure that the sampling system is free of leakage, and to ensure that the filters are not obstructing the sample flow.
(c) Any instrument used for leak survey should be tested for operation at each start-up and periodically tested during a survey.

4.7 Calibration of instruments.

Each instrument used for leak detection and evaluation should be calibrated at the following times in accordance with the manufacturer's recommended calibration instructions.

  (a) After any repair or replacement of parts.
  (b) On a regular schedule giving consideration to the type and usage of the instrument involved. HFI and CGI instruments should be checked for calibration at least once each month while in use.
  (c) At any time it is suspected that the instrument's calibration has changed.

5 LEAK INVESTIGATION AND CLASSIFICATION

5.1 Scope.

(a) Leak investigation and leak classification provide a means for determining the location, extent, and potential hazard of migrating gas. A leak investigation should be initiated to address a report of a possible leak indication. Prompt action should be taken as necessary for protection of people first and then property. Leak indications may include the following.
   (1) Odor complaints.
   (2) Reports of dead or discolored vegetation.
   (3) Positive readings from leak detection equipment.

(b) Leak indications may originate from the following.
   (1) Scheduled leak surveys.
   (2) Line patrols.
   (3) Customer reports.
   (4) Reports from the general public.

(c) Regardless of their origin, leak indications should be investigated promptly to identify any hazardous condition.

(d) In any leak investigation, an operator should presume that a Grade 1 or hazardous leak might exist.

(e) Only after completing the leak investigation should an operator determine an appropriate leak classification. Leak indications may be from sources other than petroleum gas.

5.2 Procedural Guidance – General.

(a) Petroleum gas is heavier than air, and will tend to migrate downward. Leaking petroleum gas will establish flow patterns that may follow utility trench lines and the natural topography of the leak area. Petroleum gas leak patterns will be affected by the presence of a perched water table in the leak area. The petroleum gas leak pattern will change or move with the water table due to seasonal changes. When investigating a petroleum gas leak, look for low spots or dips in the roadway and around the foundations of structures where the gas is likely to accumulate.

(b) If a leak investigation is initiated by an inside odor complaint, see 5.4 below.

(c) There are situations that might warrant entering a building before checking the extent of gas migration. These can include the following.
   (1) Broken gas lines.
   (2) Gas blowing out of the ground.
   (3) Hissing, roaring, or other sounds indicating underground gas leakage.
   (4) Noticeable odor levels.
   (5) Gas in multiple underground structures that are normally connected by ducts or piping to houses, especially when the gas readings are high.
   (6) Inside odor reports in an area of underground leakage or coincident with outside odor reports.

(d) Where a leak indication appears to originate from buried piping, operator personnel should identify the extent of gas migration. If the migration pattern extends to nearby structures, the structures should be immediately checked for the presence of combustible gases. Structures may include buildings, confined spaces, and other sub-surface structures. See 5.3 below. Considerations should include the following.
   (1) If gas is found within a structure, other structures within the boundaries of the migration pattern should be checked for the presence of gas. Based on the local conditions, structures beyond the identified migration pattern may also need to be checked.
   (2) The levels of gas migrating into buildings need to be monitored so that the "make safe" actions can be initiated at appropriate times. Under these and similar conditions, it is recommended that immediate assistance be requested and the inside investigations be initiated without delay, including finding the farthest extent of gas migration.
   (3) Because leakage can be dynamic, the gas levels in nearby buildings need to be continually monitored. It is not uncommon, under extreme conditions, for buildings that had no gas detected on the initial check to have gas levels found upon subsequent checks.

(e) Personnel investigating a leak indication reported as either an "inside" or "outside" complaint should perform a visual check for the existence of other underground utilities in the area. If "outside," see 5.3 below. Examples of other underground facilities in the area of suspected gas migration include the following.
   (1) Customer-owned service lines.
   (2) Buried fuel lines.
   (3) Electric lines.
   (4) Telephone wiring.
   (5) Television cables.
   (6) Water or sewer lines.

(f) Consider the potential for gas migration under fully paved areas, ground frost, or buildings.

(g) Barholing should be part of a leak investigation. See 5.3 below for guidelines for barholing.

5.3 Procedural Guidance – Outside underground leak.

(a) Using a barhole device and CGI, the operator should barhole in the area of leak indication along and adjacent to operator's mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, risers, or service entry points to buildings. If there is an outside meter in the suspected leakage area, the operator should attempt to barhole between the service riser and the foundation wall. If there is an inside meter, the operator should attempt to barhole near the suspected location of the service entry point at the foundation wall. Look for previous markouts or other indicators that might identify the point of entry.
Note: *If the leakage pattern extends to the outside wall of a structure, the leak investigation should continue to the inside of the structure.*

(b) Use caution when barholing to avoid damage to operator facilities or other underground structures. The operator should attempt to identify, where practicable, other underground facilities and avoid barholing directly over operator piping, customer-owned piping, and other identified or suspected underground facilities.

(c) Barholing of an underground leak indication should be done in a uniform manner by pushing or manually driving the barhole into the soil. Barholes should be placed to a uniform depth and distance to adequately define the leak area. Operators might consider establishing a recommended maximum barhole depth based upon the depth of operator and other facilities. However, under certain soil and environmental conditions (e.g., clay-type soils, frost conditions), it might be necessary to barhole deeper than the established recommended maximum barhole depth. Barholes should be placed to the approximate depth of the operator's piping. Once the area of the leak indication is determined, the operator should barhole and sample with the CGI in all directions from the approximate center of the leak until zero-gas readings are detected.

(d) If a meter set is outside, observe its dial for unusual flow.

(e) Look for indications of construction activity that might have caused damage to the operator's facilities. Examples are:
   (1) Excavation.
   (2) Pavement patches.
   (3) Landscaping.
   (4) Fencing installation.
   (5) Directional drilling or boring activity.
   (6) Settling or subsidence.

(f) Look for building additions that may have been constructed over petroleum gas service lines.

(g) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak.

(h) Check available openings in the area of a leak indication. These openings may include the following.
   (1) Valve boxes.
   (2) Catch basins.
   (3) Manholes.
   (4) Vaults.

(5) Water meter boxes.
(6) Pits.
(7) Underground irrigation control boxes.
(8) Other openings that allow access to underground atmospheres.

(i) Check for migration along other buried utilities that may serve as a path for leaking gas. Paths for leaking gas might include the following.
(1) Sanitary sewer systems.
(2) Drains and drainage systems.
(3) Water mains and service lines.
(4) Telephone lines.
(5) Electric lines.
(6) Cable TV lines.

(j) Investigating readings in underground conduit structures.
(1) Underground conduits (e.g., electric, telephone, cable) or sewer and drain structures (e.g., storm, sanitary, catch basins, vent boxes) can provide unobstructed and interconnected (or exclusive) migration paths for gas. Therefore, if readings are found in these types of structures, the operator should conduct successive checks of all interconnecting manholes until zero readings are found.
(2) Buildings should also be checked to determine if interconnecting conduits are entering buildings and possibly providing migration of gas to the inside of the building. The investigation may require coverage of numerous blocks and buildings to achieve proper results.
(3) To determine which manholes are "interconnected," an operator can perform a survey of available openings, noting similarly identified manhole covers. Other techniques include the following.
(i) Contact and work with the owner-utility directly, or through one-call (observing local one-call laws).
(ii) Pull the manhole covers and observe (from the surface) the apparent directions of the conduits.
Note: Rectangular lids are common in the electrical industry. Opening this style of lid can cause damage if the lid drops through the opening. Use extreme caution when opening these lids or ask the owner-utility for assistance.
(4) After identifying all successive manholes with positive readings and the clear manholes at the ends, all gas facilities between the clear manholes should be considered to be within the area of migration and should be investigated.
(5) Due to prevailing air flow within conduit systems, it is not unusual for gas leaks to be closer to manholes with zero readings than those with positive readings.
(6) Ventilate all manholes. This should reduce readings in manholes that are farther from the leak source,
Note: This action can change the pattern of air flow within the conduit system and change readings inside buildings (if conduits connect to the adjacent buildings). Therefore, check buildings as discussed in 5.3(i)(2) above to determine if this should be a concern.
(7) Continue to pinpoint (see 7 below) the leak by barholing as described in the beginning of this section (5.3). If necessary, barhole over or near the conduit to obtain a lead to the source leak. Be cautious of other owner-utilities as discussed in 7.3(a).

(k) If a leak area involves multiple buildings, the leak investigation area should be expanded to include each building in the affected area. Consider extending the leak investigation area one or two buildings, or a specified distance, beyond the leak migration area.

(l) If the leak is detected on aboveground exposed piping, perform a bubble test using a leak detection solution to determine the magnitude of the leak. See 4.4(b) above.

(m) Based on the leak location, extent of migration, and magnitude, assign a leak classification to the leak area. See Tables 3a, 3b, and 3c.

5.4 Procedural Guidance – Inside leak or odor complaint.

(a) It may be necessary to investigate a reported leak or gas odor inside a structure. These investigations may result from the following.

(1) Gas migration.
(2) Indications of gas readings inside a building while performing routine leak surveys.
(3) Odor complaints.

(b) Leaks may originate on customer-owned piping or equipment.

(c) Look for indications of construction activity, which may have caused damage to the operator's facilities. Examples are:
(1) Excavation.
(2) Pavement patches.
(3) Landscaping.
(4) Fencing installation.
(5) Directional drilling or boring activity.
(6) Settling or subsidence.

(d) Look for building additions that may have been constructed over petroleum gas service lines.

(e) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak. See 5.3 above.

(f) The CGI and an approved flashlight should be turned on prior to entering any building or structure.

(g) If there is an outside meter set, observe its dial for excessive flow or movement.

(h) Using a CGI, test around the entry door for gas indications. Do not ring the doorbell; knock on the door to get the attention of occupants. Upon entry do not operate any lights, but do take appropriate precautions to prevent accidental ignition. Immediately sample the inside atmosphere for the presence of combustible gas. Petroleum gas is heavier than air and will accumulate in the lower atmosphere.
Note: If gas is detected, the applicable portions of the operator's emergency procedures need to be implemented.

(i) If the call is an odor complaint, proceed to the area indicated by the caller/occupant to investigate. When entering a building as a result of detecting a leak on outside underground piping, initiate an "inside" investigation. If the visit is in response to an odor complaint, attempt to locate and identify all gas lines associated with the building to their respective points of termination or equipment connection. Observe for abandoned or inactive petroleum gas lines, and petroleum gas lines that may exist under a portion of the structure that has no basement (e.g., an addition, garage).

(j) If the building has a basement, enter it while constantly sampling with a CGI. Proceed to check the following with the CGI.
(1) Basement wall that is adjacent to the outside leak area for migration of gas.
(2) Gas piping that passes through basement walls.
(3) Cracks in basement walls.
(4) Other utility entry points, floor drains, laundry sink drains, bathroom drains, and toilets for the presence of combustible gases.
(5) Basement walls adjacent to buried gas piping.

(k) If the structure has no basement, but has a crawlspace, attempt to gain access to the crawlspace and sample its atmosphere for the presence of combustible gases. If the structure is built on a concrete slab, check all utility penetration points for gas indications. Attempt to barhole at an angle under the concrete slab along the leak area and near utility entrances for gas indications.

(l) Use the CGI and a leak detection solution to locate the source of the gas odor, and to identify the degree of potential hazard.

(m) Using a barhole device and CGI, the operator should barhole in the area of indication along and adjacent to operator's mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, risers, or service entry points to buildings. If there is an outside meter in the suspected leakage area, the operator should attempt to barhole between the service riser and the foundational wall. Look for previous markouts or other indicators that might identify the point of entry.
Note: If the leakage pattern extends to the outside wall of a structure, the leak investigation should continue to the inside of the structure.
(1) Use caution when barholing to avoid damages to operator facilities or other underground structures. The operator should attempt to identify, where practicable, other underground facilities and avoid barholing directly over operator piping, customer-owned piping, and other

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

Note: API STD 1163, NACE SP0120, and ANSI/ASNT ILI-PQ are incorporated by reference (see §192.7).

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
General A	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	NOTE: Pipe transported by railroad before November 12, 1970, may have been qualified for use by pressure testing, prior to October 1, 2015 (refer to Amendment 192-120), 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
		192.227(c)	Individual welder qualification at time of construction of steel transmission line, and offshore and onshore Type A gathering line	Records
		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

Joining of Materials other than by Welding F	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, records

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	Notification 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

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Subpart	Section	Subject	Requirements
I Requirements for Corrosion Control (Continued)	192.473	External corrosion control: Interference currents	Program
	192.475	Internal corrosion control: General	Investigation, inspection
	192.476	Internal corrosion control: Design & construction of transmission line	Evaluation, records
	192.477	Internal corrosion control: Monitoring	Check
	192.479	Atmospheric corrosion control: General	Test, investigation
	192.481	Atmospheric corrosion control: Monitoring	Inspection
	192.490	Direct assessment	Assessment
	192.491	Corrosion control records	Records or maps
J Test Requirements	192.503	Test requirements: General	Test
	192.505	Strength test requirements: Pipelines to operate at 30% or more of SMYS	Test, manufacturer certification
	192.507	Test requirements: Pipelines to operate at less than 30% of SMYS	Test, test procedure, leak test
	192.509	Test requirements: Pipelines to operate below 100 psig	Test procedure, leak test
	192.511	Test requirements: Service lines	Leak test
	192.513	Test requirements: Plastic pipelines	Test procedure, test
	192.517	Test requirements: Records	Records
K Uprating	192.553	Uprating: General requirements	Records, written procedure, leak check
	192.555	Uprating: Hoop stress at 30% or more of SMYS	Review, test (if necessary)
	192.557	Uprating: Hoop stress at less than 30% of SMYS	Review, leak survey, test (if necessary)
L Operations	192.603	General provisions (operations)	Records
	192.605	Procedural manual for operations, maintenance, and emergencies	Written procedures
	192.609	Change in class location: Required study	Study

Table Continued

Subpart	Section	Subject	Requirements
O	192.915	Knowledge and training of IMP personnel	Program provisions – Address 3 primary areas regarding personnel (see §192.915)
Gas Transmission Pipeline Integrity Management (Continued)	192.917	Identifying/addressing potential threats to pipeline integrity	Identify/address threats (see numerous actions in §192.917)
	192.919	Baseline assessment plan	Written plan – Address 5 elements (see §192.919)
	192.921	Conducting baseline assessment	Method selection, assessment
	192.923	Direct assessment	Plans
	192.925	External Corrosion Direct Assessment (ECDA) requirements	Plan/procedures – 4 separate steps (see §192.925)
	192.927	Internal Corrosion Direct Assessment (ICDA) requirements	Plan – 4 separate parts (see §192.927)
	192.929	Stress Corrosion Cracking Direct Assessment (SCCDA) requirements	Plan – Data gathering and integration, assessment method
	192.931	Confirmatory Direct Assessment (CDA) requirements	Plans – External corrosion and internal corrosion, schedule
	192.933	Actions to address integrity issues	Evaluation, demonstrate, notification, schedule, records, monitoring
	192.935	Additional preventative and mitigative measures	Measures (see numerous P&M measures in §192.935)
	192.937	Continual process of evaluation and assessment	Assessment, evaluation
	192.939	Required reassessment intervals	Establish intervals
	192.941	Low stress reassessment	Electrical survey, evaluation, leak survey, identification, analysis, tests, records integration
	192.945	Methods to measure program effectiveness	Program (4 performance measures in ASME B31.8S), reports, monitoring
	192.947	Recordkeeping	Records

Table Continued

Subpart	Section	Subject	Requirements
P Gas Distribution Pipeline Integrity Management	192.1005	Implementing Subpart P	Program, written plan
	192.1007	Elements of integrity management plan	Written plan - 7 elements (see §192.1007), report
	192.1011	Recordkeeping	Records
	192.1015	Implementing Subpart P for a master meter or LPG operator	Program, written plan - 6 elements (see §192.1015), records

GUIDE MATERIAL APPENDIX G-192-21

(See guide material under §§191.1 and 192.1)

OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION LETTERS

1 SCOPE

This appendix includes letters from the Occupational Safety and Health Administration (OSHA) regarding application of their standards to working conditions that are regulated by PHMSA-OPS.

2 LETTERS

The following letters are assembled here for reference:

- OSHA letter to AGA dated April 8, 1999 re: Respiratory Protection — Exhibit 1
- OSHA letter to AGA dated May 25, 1994 re: Confined Space — Exhibit 2
- OSHA letter to AGA dated July 19, 1990 re: Excavation Standards — Exhibit 3

U.S. Department of Labor

Occupational Safety and Health Administration
Washington, D.C. 20210

Reply to the Attention of: DCP/OHCA/CM

APR 8 1999

Mr. Kevin Belford, Esq.
General Counsel
American Gas Association
1515 Wilson Boulevard
Arlington, Virginia 22209

Dear Mr. Belford:

This letter is in response to several inquiries submitted to the Occupational Safety and Health Administration (OSHA) from pipeline owners and operators: Gordon Murdock of Questar, Greg Janson of Southwest Gas Corporation, and Stephen M. Sablack of Sempra Energy, as to whether OSHA is preempted from enforcing its recently revised Respiratory Protection Standard located at 29 CFR 1910.134 by regulations issued by the Department of Transportation's Office of Pipeline Safety (OPS).

Section 4(b)(1) of the Occupational Safety and Health Act, 29 U.S.C. § 653(b)(1), precludes OSHA from applying its standards to working conditions that are regulated by other federal agencies. In order for a working condition to qualify for the exemption, the other federal agency must have statutory authority to regulate the health and safety of working conditions of employees and must exercise that authority by standards or regulations having the force and effect of law. Section 4(b)(1) does not create an industry-wide exemption. It only exempts specific "working conditions" that are subject to the worker safety or health regulations of other agencies.

OPS has promulgated regulations which address the provision and use of breathing apparatus to protect workers against hazardous air contaminants. 49 CFR 192.605 provides, *inter alia*, that each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. Section 192.605(b)(9) provides that the manual must include procedures for "[t]aking 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." Additionally, OPS regulations provide that each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. 49 CFR 192.615(a). At a minimum, the procedures must provide for the availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency. 49 CFR 192.615(a)(4). Section 192.615(b)(1) requires each operator to furnish the latest emergency procedure to its supervisors who are responsible for emergency action. Section 192.615(b)(2) requires each operator to train appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and to verify that the training is effective.

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