January 9, 2017

Dear Guide Purchaser,


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

Sincerely,

[Signature]

Secretary
GPTC Z380
The changes in this addendum are marked by wide vertical lines inserted to the left of modified text, overwriting the left border of most tables, or a block symbol (▌) where needed. The Federal Regulations were updated with one amendment and associated correction (amendment 192-121) that affected 3 sections of the Regulations and 4 sections of the Guide. Eight GPTC transactions affected 18 sections of the Guide.

Editorial updates include application of the Editorial Guidelines, adjustments to page numbering, and adjustment of text on pages. While only significant editorial updates are marked, all affected pages carry the current addendum footnote. Editorial updates as indicated “EU” affected 6 sections of the Guide (plus other sections impacted by page adjustments, etc.).

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

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Committee Scope

The Gas Piping Technology Committee (GPTC) is an independent technical group of individuals with expertise in, and concern for, natural gas pipeline safety and is responsible for:

- Developing and maintaining ANSI Technical Reports regarding the application of natural gas pipeline technology and operating or maintenance practices.
- Promoting the use of voluntary consensus standards.
• Petitioning the United States Department of Transportation (DOT) for changes in Federal Natural Gas Pipeline Safety Regulations based on the technical expertise of the GPTC.
• When deemed appropriate by the Main Body, commenting on Advanced Notice of Proposed Rulemakings, Notice of Proposed Rulemakings, Final Rules, and other regulatory notices issued by DOT involving such regulations.
• Reviewing applicable National Transportation Safety Board (NTSB) reports, DOT and State Pipeline Safety Agency incident reports, and taking appropriate action including that of responding to recommendations issued to the GPTC.
• Taking such actions that are necessary and proper to further the safe application of natural gas pipeline technology.
## GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation

<table>
<thead>
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<th>Member Name</th>
<th>Position</th>
<th>Abbreviations</th>
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<th>Manufacturers</th>
<th>Transmission</th>
<th>Design</th>
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<th>Plastic Pipe</th>
<th>Editorial</th>
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Addendum 5, July 2016  xxiii
GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation (Continued)

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- **Damage Prevention - Emergency Response:** DP/ER
- **Operations and Maintenance - Operator Qualification:** O&M/OQ

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Addendum 6, December 2016  xxiv
### GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation (Continued)

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### GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation (Continued)

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| Friend, Mary S. | X | X | X | |
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### GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation (Continued)

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| PHMSA , Washington, DC | X | X | X | X |

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| Black & Veatch Corporation, Knoxville, TN | X | X | | | | | | | | | |

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Addendum 5, July 2016
## GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation (Continued)

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LETTER TO GAS PIPING TECHNOLOGY COMMITTEE FROM THE U.S. DEPARTMENT OF TRANSPORTATION

FEBRUARY 11, 2015

Ms. Leticia Quezada
Chair, Gas Piping Technology Committee
Nicor Gas
1844 Ferry Road
Naperville, IL 60563-9662

Dear Ms. Quezada:

The U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) appreciates the cooperative effort needed to develop the Guide for Gas Transmission, Distribution, and Gathering Piping Systems (Guide). The Guide, advisory in nature, provides clear and concise guidance to gas piping systems operators on complying with the Federal pipeline safety standards. PHMSA recognizes the efforts of the Gas Piping Technology Committee (GPTC) to enhance the pipeline safety practices of those who use the Guide.

PHMSA looks forward to the continued and coordinated efforts by the GPTC members toward improvements in pipeline safety practices through the use of the Guide.

Sincerely,

Jeffrey D. Wiese
Associate Administrator for Pipeline Safety
AMERICAN GAS ASSOCIATION (AGA)
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EDITORIAL CONVENTIONS OF THE GUIDE

Practices Used in the Guide

♦ If the guide material does not cover all the specific elements in a section of the Federal Regulations (Regulation(s)), and there is no editorial note, no other guide material has been deemed necessary by the Gas Piping Technology Committee (Committee).

♦ The term "includes" does not limit any list to those items presented and means, "includes but not limited to." This term is used in the same manner as it is used in the Regulations (reference §192.15). Further, added qualifiers such as "may" or "might" are sometimes used to emphasize that a list is not intended to set a minimum requirement or practice.

♦ The term "should" indicates recommendations that are not mandatory, but are to be acted upon as appropriate. As such, this guide material is advisory in nature, and operators may use it (or other equally acceptable methods) for a regulatory compliance aid.

♦ All figures and tables located in the basic guide material are designated by the corresponding Regulation section number followed by a capital letter for figures (sequentially), or lower case Roman numeral for tables (e.g., FIGURE 192.485A or TABLE 192.485i).

♦ The date shown in the title block for each section is the effective date of the original Regulation or its latest amendment.

♦ Sections of the Regulations that have been deleted are not listed by title in the Contents unless reserved by the Regulations. However, the section numbers have been retained in the Guide, along with their effective date of removal (e.g., §192.57, Removed and reserved. [Effective 03/08/89]).

♦ Sections of the Regulations having a future effective date may be presented for both the current and new requirements and with the effective date emphasized. In such case, the guide material is subject to review in light of the new requirements.

Common Notes in the Guide

♦ No guide material necessary. In the opinion of the Committee, the Regulation section is self-explanatory and no additional information is provided.

♦ No guide material available at present. The Committee has not issued guide material or has not yet determined if guide material is necessary.

♦ This guide material is under review following Amendment (either 19x-yy or control number). The Committee is currently reviewing the amendment.

♦ Discontinued or Withdrawn. Where either of these words accompanies a listing of an industry standard or other published reference, it indicates that the document is no longer current or has been withdrawn, and may not be available from its original source. The document may be available from an alternate source. When using such a document, care should be taken to determine the validity of the material and the reason for which it was discontinued or withdrawn.

♦ See §19x.xxx, refers to Regulation Section 19x.xxx and the guide material directly beneath it.
♦ See x of the guide material under §19y.yyy. This refers to Section x of the guide material directly beneath §19y.yyy.

♦ See x above (or below). This refers to Section x of the guide material in which the reference appears.
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* Issued as a Direct Final Rule (DFR) or Interim Final Rule.
Reserved
PART 191

ANNUAL REPORTS, INCIDENT REPORTS, AND
SAFETY-RELATED CONDITION REPORTS


§191.1
Scope.

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

(b) This part does not apply to—

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

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

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

(4) Onshore gathering of gas—

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

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

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


GUIDE MATERIAL

(a) For offshore pipelines, responsibilities have been assigned to the Department of Transportation and the Department of the Interior in accordance with their Memorandum of Understanding dated December 10, 1996 (Implemented per Federal Register, Vol. 62, No. 223, November 19, 1997). See Guide Material Appendix G-192-19.
(b) State regulations may be more stringent and require additional reporting for operators of intrastate pipelines. A NAPSR document (1st Edition 2011) provides a compendium of these additional state requirements and is available at www.napsr.org.

(c) The Occupational Safety and Health Administration has issued letters regarding application of their standards to working conditions that are regulated by PHMSA-OPS. See Guide Material Appendix G-192-21.

§191.3
Definitions.

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

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

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

Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
   (i) A death, or personal injury necessitating in-patient hospitalization;
   (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;
   (iii) Unintentional estimated gas loss of three million cubic feet or more;

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

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

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

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

Municipality means a city, count or any other political subdivision of a state;

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

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

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

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

Pipeline or Pipeline System means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.
State includes each of the several states, the District of Columbia, and the Commonwealth of Puerto Rico;

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


GUIDE MATERIAL

ADDITIONAL INCIDENT CONSIDERATIONS

(a) State regulations may be more stringent and require additional reporting for operators of intrastate pipelines.

(b) "In-patient hospitalization" means hospital admission and at least one overnight stay.

(c) Estimated property damage includes, but is not limited to, costs due to:
   (1) Property damage to operator's facilities and property of others.
   (2) Facility repair and replacement.
   (3) Restoration of gas distribution service and relighting customers.
   (4) Leak locating.
   (5) Right-of-way cleanup.
   (6) Environmental cleanup and damage.

(d) Items to be considered when determining if an event may be significant include the following.
   (1) Rupture or explosion.
   (2) Fire.
   (3) Loss of service.
   (4) Evacuation of people in the area.
   (5) Involvement of local emergency response personnel.
   (6) Degree of media involvement.

(e) For guidance on calculating gas loss from a damaged pipeline, see Guide Material Appendix G-191-9.

§191.5
Immediate notice of certain incidents.

[Effective Date: 01/01/11]

(a) At the earliest practicable moment following discovery, each operator shall give notice in accordance with paragraph (b) of this section of each incident as defined in §191.3.

(b) Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800–424–8802 (in Washington, DC, 202 267–2675) or electronically at http://www.nrc.uscg.mil and must include the following information:
   (1) Names of operator and person making report and their telephone numbers.
   (2) The location of the incident.
   (3) The time of the incident.
   (4) The number of fatalities and personal injuries, if any.
   (5) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.
GUIDE MATERIAL

(a) Complete information is not necessary for the initial electronic or telephonic incident report to National Response Center (NRC). Refer to Guide Material Appendix G-191-1 for a sample worksheet that may be used to compile information for the incident report. The initial incident report should be made within 2 hours of discovery of the incident. Initial report information should include the following.

(1) Name, address, and a 24-hour telephone number of the operator. An operator should consider providing a telephone number where more detailed information can be obtained.

(2) Time and date of incident.

(3) Location of incident, provided in a manner that will aid agencies in locating the site on maps. GPS coordinates, addresses and ZIP codes, and cross streets are useful.

(4) Facilities involved.

(5) Number of fatalities or injuries, if known.

(6) Estimate of property damage.

(7) Type of product released, and an estimate of the quantity released. For guidance on calculating gas loss from a damaged pipeline, see Guide Material Appendix G-191-9.

(8) Evacuations, if known.

(9) The responsible party, if known.

(10) Weather conditions at the incident site.

(b) If an incident report has been made and further investigation reveals that the event was not an "incident," and therefore not reportable, the report should be nullified with a letter. This letter should be sent to the Information Resources Manager at the address specified in §191.7 within 30 days of the event. The letter should reference the NRC incident report number issued when the initial notification was made and briefly explain why the incident report is being nullified. Incident reports cannot be removed from the database, but the letter may help ensure accurate PHMSA-OPS records.

(c) Operators should consider making an additional report if there is a significant change in the data previously provided to the NRC. A significant change may include an increase or decrease in the number of injuries or fatalities previously reported, or a revised estimate of property damage that is at least 10 times that previously reported. Consideration should be given to making an additional report up to 48 hours following the initial report. The operator should clearly report to the NRC that additional information is being provided and give the NRC the initial report's assigned NRC Report Number. However, any report following the initial report will result in an additional NRC Report Number being created for the same event. All related NRC Report Numbers should be referenced in the PHMSA-OPS electronic or written incident report (see §§191.9 and 191.15).

(d) For intrastate pipelines, it is necessary to comply with federal reporting requirements even though an "incident" has been reported to the appropriate state agency.

§191.7
Report submission requirements.

(a) General. Except as provided in paragraphs (b) and (e) of this section, an operator must submit each report required by this part electronically to the Pipeline and Hazardous Materials Safety Administration at http://portal.phmsa.dot.gov/pipeline unless an alternative reporting method is
PART 192

MINIMUM FEDERAL SAFETY STANDARDS


SUBPART A
GENERAL

§192.1
What is the scope of this part?
[Effective Date: 03/05/07]

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

(b) This part does not apply to—

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

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

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

(4) Onshore gathering of gas—

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

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

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

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

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

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

GUIDE MATERIAL

(a) The guide material presented in this Guide includes information and some acceptable methods to assist the operator in complying with the Minimum Federal Safety Standards. The recommendations contained in the Guide are based on sound engineering principles, developed by a committee balanced in accordance with accepted committee procedures, and must be applied by the use of sound and competent engineering judgment. The guide material is advisory in nature and should not restrict the operator from using other methods of complying. In addition, the operator is cautioned that the guide material may not be adequate under all conditions encountered.

(b) While the GPTC Guide is intended principally to guide operators of natural gas pipelines, it is a valuable reference for operators of other pipelines covered by Part 192. The user is cautioned that the unique properties and characteristics associated with other gases (e.g., toxicity, density, corrosivity, and temperature extremes) may require special engineering, operations, and maintenance considerations. Also, the unique properties and toxicity of other gases can represent significant hazards that need to be considered but are not specifically addressed in the Guide. Operators of petroleum gas distribution systems may benefit from information provided in the "Training Guide for Operators of Small LP Gas Systems" (also referred to as "Guidance Manual") available at www.phmsa.dot.gov/pipeline/tq/manuals.

(c) As used in the Guide, the terms Personnel, Employees, and Workers refer to operator employees and, unless specifically noted otherwise, include other personnel used by operators to perform Part 192 functions.

(d) The operator is responsible for the work of a contractor performing tasks covered under Part 192. The operator should ensure that contract personnel are familiar with applicable procedures prior to the start of work.


(f) For offshore pipelines, responsibilities have been assigned to the Department of Transportation and the Department of the Interior in accordance with their Memorandum of Understanding dated December 10, 1996 (Implemented per Federal Register, Vol. 62, No. 223, November 19, 1997). See Guide Material Appendix G-192-19.

(g) Additional state requirements may exist for intrastate facilities. A NAPSR document (1st Edition 2011) provides a compendium of these additional state requirements and is available at www.napsr.org.

(h) The Occupational Safety and Health Administration has issued letters regarding application of their standards to working conditions that are regulated by PHMSA-OPS. See Guide Material Appendix G-192-21.

§192.3
Definitions.
[Effective Date: 10/01/15]

As used in this part:
*Abandoned* means permanently removed from service.
*Active corrosion* means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.
**Administrator** means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Person** means any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.
Petroleum gas means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 °F (38 °C).

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

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

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

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

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

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

SMYS means specified minimum yield strength is:

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

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

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

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

Transmission line means a pipeline, other than a gathering line, that:

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

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

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

Welding operator means a person who operates machine or automatic welding equipment.
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, forged, or spun end closures; and (2) tested in the manufacturer's plant. See also Bottle-type holder.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

\[
\begin{align*}
A &= 100 \, ^\circ F \\
B &= 120 \, ^\circ F \\
C &= 140 \, ^\circ F \\
D &= 160 \, ^\circ F \\
E &= 180 \, ^\circ F
\end{align*}
\]

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

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

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

§192.65
Transportation of pipe.

[Effective Date: 10/01/15]

(a) *Railroad.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not install pipe having an outer diameter to wall thickness of 70 to 1, or more, that is transported by railroad unless the transportation is performed by API RP 5L1 (incorporated by reference, see §192.7).

(b) *Ship or barge.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference, see §192.7).

(c) *Truck.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, see § 192.7).

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

No guide material necessary
§192.165
Compressor stations: Liquid removal.

[Effective Date: 10/01/15]

(a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

(b) Each liquid separator used to remove entrained liquids at a compressor station must —
   (1) Have a manually operable means of removing these liquids.
   (2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and
   (3) Be manufactured in accordance with section VIII ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see §192.7) and the additional requirements of §192.153(e) except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

[Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

(a) Liquid separators that are installed in compressor station piping to protect the compressor from the introduction of liquid in quantities that could cause damage should be designed in accordance with §192.165(b)(1), (2) and (3).

(b) When liquid removal facilities (e.g., pigging receiver tanks, slug catchers, drips and sumps) are installed in the pipeline outside the compressor station piping, they should be designed as fabricated assemblies rather than as part of the station piping.

§192.167
Compressor stations: Emergency shutdown.

[Effective Date: 07/13/98]

(a) Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:
   (1) It must be able to block gas out of the station and blow down the station piping.
   (2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.
   (3) It must provide means for the shutdown of gas compression equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except, that—
      (i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and
      (ii) Electrical circuits needed to protect equipment from damage may remain energized.
   (4) It must be operable from at least two locations, each of which is—
      (i) Outside the gas area of the station;
(ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and

(iii) Not more than 500 feet (153 meters) from the limits of the station.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

(1) In the case of an unattended compressor station—
   (i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or
   (ii) When an uncontrolled fire occurs on the platform; and

(2) In the case of a compressor station in a building—
   (i) When an uncontrolled fire occurs in the building; or
   (ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition.

For the purpose of paragraph (c)(2)(ii) of this section, an electrical facility that conforms to Class 1, Group D of the National Electrical Code is not a source of ignition.

[Amtd. 192-27, 41 FR 34598, Aug. 16, 1976; Amtd. 192-85, 63 FR 37500, July 13, 1998]

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1 EMERGENCY SHUTDOWN SYSTEMS

Gas pipeline facilities that are subject to the emergency shutdown (ESD) requirements are limited to those that are part of a compressor station. The purpose of an actuated ESD is to safely deactivate the compressor station if a hazardous condition (e.g., fire, gas leak) is detected. Safe deactivation should include:

(a) Eliminating sources of ignition (except for electrical circuits required for emergency evacuation or for protecting equipment); and

(b) Isolating compressor station piping from fuel sources, eliminating as much fuel as practicable in a time frame defined by the operator.

Using ESD systems for other than intended purposes could result in a malfunction or unintentional activation. If the compressor station is the primary supply of gas for a distribution system, the ESD must be designed to prevent an unintended outage to customers (§192.167(b)).

1.1 Compressor station boundaries.

(a) The term compressor station is often associated with the fenced area or property that contains facilities associated with mechanically boosting the gas pressure in the pipeline. Facilities not associated with boosting gas pressure (e.g., regulation or meter stations, interconnecting facilities with another operator, pig launching/receiving facilities, warehousing) are not uncommon within the station area. However, for complying with the requirements in Part 192 related to compressor stations, the compressor station should include only those facilities installed for the purpose of increasing the pressure of gas as it flows down the pipeline or for reducing back-pressure on upstream gas facilities to enhance flow. It includes the equipment installed for this purpose and piping, components, and appurtenances used to connect and support the equipment in the process of increasing the pressure downstream.

(b) The operator should consider ancillary equipment that could be impacted during an ESD event. Such equipment may include the following.

(1) High-pressure gas piping that interconnects equipment or piping systems.

(2) Fuel gas systems.
(3) Lubrication systems.
(4) Air systems.
(5) Cooling systems.
(6) Hydraulic systems.

(c) Gas used for service to buildings (e.g., office, storage, warehouse) should be isolated from the gas source during an ESD but may not be required to be blown down.

Note: Boundaries of a compressor station can change over time whenever piping or equipment modifications are made to the facility. Resulting changes in station boundaries should trigger consideration for updating the ESD system to incorporate any changes in the station piping boundary.

1.2 Isolation and blowdown valves.
(a) Isolation valves are necessary to block gas from entering the compressor station piping when an ESD is activated.
(b) Blowdown valves are necessary for venting gas from the compressor station piping when an ESD is activated. The blowdown valves and stacks should be sized, located, and designed to accomplish the following:
   (1) Quickly evacuate gas from the station piping.
   (2) Minimize the venting time.
   (3) Discharge gas into the atmosphere without undue hazard.
   (4) Prevent detrimental accumulation of water, ice, or snow in blowdown stacks.
(c) Isolation and blowdown valves used in an ESD should be identified on station drawings to support ESD testing and facility modifications that may require changes to the ESD system.
(d) Operators should physically mark ESD valves (e.g., by painting them red, signage, tags) to make them clearly identifiable.

1.3 ESD actuation.
(a) An operator may use a combination of automated devices and manual switches.
(b) The operator should evaluate the location and type of manual ESD switches to prevent accidental operation.
(c) Any device (manual or automated) that can be used to activate an ESD must be tested per the requirements of §192.731.

§192.169
Compressor stations: Pressure limiting devices.
[Effective Date: 11/12/70]

(a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.
(b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

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Overpressure protection devices or automatic compressor shutdown devices (e.g., transducers, software) should be installed to protect the discharge line of each compressor between the gas compressor and the first discharge block valve. The total capacity of relief devices should be equal to or greater than the capacity of that compressor.
If using overpressure protection devices on the discharge side of a compressor to protect station piping or downstream pipelines, the allowable overpressure limit is governed by the following.

(a) 10% above the MAOP (§192.169(a)).
(b) 75% of the SMYS of the pipe (see §192.201(a)(2)(i)).
(c) 4% above the MAOP for a steel pipeline where the MAOP is determined under §192.620 (see §192.620(e)(1)).
(d) For a steel pipeline with an MAOP of 60 psig or higher and covered under §192.619(c) (see §192.739(b)):
   (1) 4% above an MAOP that produces a hoop stress over 72% SMYS.
   (2) If the percentage of SMYS is unknown, a safe pipeline pressure considering operating and maintenance history.
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.

<table>
<thead>
<tr>
<th>Tube Size (OD inches)</th>
<th>Support Spacing (feet)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/2</td>
<td>4</td>
</tr>
<tr>
<td>5/8 or 3/4</td>
<td>6</td>
</tr>
<tr>
<td>7/8 or 1 1/8</td>
<td>8</td>
</tr>
</tbody>
</table>

TABLE 192.377i

§192.379
New service lines not in use.
[Effective Date: 11/03/72]

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas;
   (a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.
   (b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
   (c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

[Issued by Amdt. 192-8, 37 FR 20694, Oct. 3, 1972]

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No guide material necessary.
§192.381  
Service lines: Excess flow valve performance standards.  
[Effective Date: 04/14/17]  

(a) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

   (1) Function properly up to the maximum operating pressure at which the valve is rated;
   (2) Function properly at all temperatures reasonably expected in the operating environment of the service line;
   (3) At 10 p.s.i. (69 kPa) gage;
      (i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and
      (ii) Upon closure, reduce gas flow —
          (A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or
          (B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and
   (4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

(b) An excess flow valve must meet the applicable requirements of Subparts B and D of this part.

(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

(d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

(e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.


GUIDE MATERIAL  

1 GENERAL  

The following provides operators with guide material when using an Excess Flow Valve (EFV). See guide material under §192.3 for the definitions of EFV, EFV-Bypass (EFVB), and EFV-Non-Bypass (EFVNB).
4.4 Application of heat.
Exposure to heat when performing such tasks as tie-ins or coating applications should be controlled to avoid adversely affecting the EFV. To prevent damaging the mechanism, care should be taken on steel installations to keep welding heat away from the EFV. In some circumstances, a wet rag may be placed over the steel nipple housing the EFV when the valve is being welded in place. Otherwise the steel nipple housing the EFV should be of appropriate length to allow necessary weld heat dissipation.

4.5 Pressure testing.
When performing a pre-installation pressure test through the upstream lateral tee, a rapid re-pressurization of the line should be avoided because such action might damage or close the downstream EFV.

4.6 Post-installation activation test.
After installation, consider testing the EFV to ensure that it trips and then resets. To test, trip the EFV by venting the service line to atmosphere. Then, follow the manufacturer's reset procedure.

4.7 Purging a service line.
Care should be taken to avoid excess flow that would cause the EFV to close. Techniques to avoid closure include opening the meter valve slowly, using an orifice cap, or purging the service line through the regulator.

5 IDENTIFICATION CONSIDERATIONS

Marking and identifying that an EFV has been installed may be accomplished by one or more of the following.
(a) Affixing a durable identifying tag to the exposed portion of the gas riser or meter set.
(b) Indicating the presence of an EFV on maps or records.
(c) Using GPS coordinates.
(d) Using a passive electronic marker.
(e) Other methods.

§192.383
Excess flow valve installation.

(a) Definitions. As used in this section:
Branched service line means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.
Replaced service line means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.
Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence (SFR).
(b) Installation required. An EFV installation must comply with the performance standards in §192.381. After April 14, 2017 each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated:
(1) A single service 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.

1 EXCESS FLOW VALVES (EFV) INSTALLATIONS

1.1 General.
Section 192.383 requires an EFV to be installed on new or replaced service lines to single-family residences unless one or more of four conditions listed in §192.383(b) is present. The following guide material provides installation considerations for EFVs. Also, see 4 of the guide material under §192.381.

Note: OPS Advisory Bulletin ADB-08-04 (73 FR 32077, June 5, 2008; see Guide Material Appendix G-192-1, Section 2) was published prior to the effective date of Amendment 192-113, which amended §192.383.

1.2 Service line supplying a single-family residence.
(a) The following illustrations (Figures 192.383A and 192.383B) show where an EFV should normally be installed on a service line to comply with §192.381(d). For other EFV installation considerations, see guide material under §192.381.
1.3 Service line supplying multiple single-family residences.
An operator may choose to install an EFV on a service line to multiple single-family residences. An EFV may not be practical in certain installations such as branch (split) service lines or multiple-meter manifolds due to the varying loads of multiple residences. Examples of a service line to multiple single-family residences are illustrated in Figures 192.383C and 192.383D. For other EFV installation considerations, see the conditions listed in §192.383(b) and the guide material under §192.381.

Branch Service Line Serving 2 Single Residences with 1 EFV

Branch Service Line Serving 2 Single Residences with 2 EFVs

§192.385
Manual service line shut-off valve installation.

(a) Definitions. As used in this section:
Manual service line shut-off valve means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.
(b) Installation requirement. The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH.
(c) Accessibility and maintenance. Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this section are subject to regular scheduled maintenance, as documented by the operator and consistent with the valve manufacturer’s specification.

[Issued by Amdt. 192-121, 81 FR 70987, Oct. 14, 2016 with Amdt. 192-121 Correction, 81 FR 72739, Oct. 21, 2016]
BLANK
(c) In order that intelligent interpretation of pressure variations can be made, it is important that accurate thermometers, deadweight pressure gauges, meters, etc. be used and that the readings be taken at properly located points and at proper intervals of time.

4.2 Test procedure.
It is recommended that pressure in the test segment be applied in increments equal to 25% of the total test pressure. At the end of each incremental increase, the pressure should be maintained while the test segment is checked for leaks or other sources of rapid decline in pressure.

4.3 Locating leaks.
The location of leaks may be determined visually, by sound, by smell, or by utilizing leak detection equipment. The leak detection method to be used is dependent upon the test media. Caution - multiple leaks may exist.

4.4 Repairs.
It may be prudent to lower pressure in the test segment prior to exposing the pipe for repair. While temporary repairs may be made to accommodate the test, permanent repairs must satisfy requirements of §§192.309, 192.711, 192.713, 192.715, and 192.717 as applicable.

5 Records
See guide material under §192.517.

§192.507
Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.
[Effective Date: 07/13/98]

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:
(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.
(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium —
   (1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or
   (2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.
(c) The pressure must be maintained at or above the test pressure for at least 1 hour.

[Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL
See 1(b), 1(c), 2, 3, and 4 of the guide material under §192.505; guide material under §§192.515 and 192.517; and Guide Material Appendices G-192-9, G-192-9A, and G-192-10.
§192.509  Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.  
[Effective Date: 07/13/98]

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:
(a) The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested.
(b) Each main that is to be operated at less than 1 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested at least 90 p.s.i. (621 kPa) gage.

[Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 GENERAL
See 1(b) of the guide material under §192.505; guide material under §§192.515 and 192.517; and Guide Material Appendix G-192-9.

2 TEST DURATION
(a) See 4(a) and (b) of the guide material under §192.513.
(b) An example of an approach to determine the test durations for steel pipe at typical diameters and lengths is presented in Table 192.509i. These durations do not include the time to pressurize the test segments, time for temperature stabilization, or the time for depressurizing the test segments. The test period should begin when the pressure of the test medium stabilizes.
(c) The time required to reach the test pressure and temperature stabilization depends on several factors, including pipe diameter, pipe length, whether the pipe segment is buried or exposed to the atmosphere, and the initial temperatures of the test segment, pressurizing medium, and the environment around the test segment.
(d) Temperature variations during the test period could affect the gauge pressure and should be considered.
Example Leak Test Duration for Steel Pipe (hours)

<table>
<thead>
<tr>
<th>Nominal Pipe Size (ID in.)</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>6</th>
<th>8</th>
<th>10</th>
<th>12</th>
</tr>
</thead>
<tbody>
<tr>
<td>Schedule</td>
<td>40</td>
<td>40</td>
<td>40</td>
<td>40</td>
<td>40</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>Length (ft.)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>50</td>
<td>1/4</td>
<td>1/4</td>
<td>1/4</td>
<td>1/2</td>
<td>1/2</td>
<td>3/4</td>
<td>1 1/4</td>
</tr>
<tr>
<td>100</td>
<td>1/4</td>
<td>1/4</td>
<td>1/4</td>
<td>3/4</td>
<td>1</td>
<td>1 1/2</td>
<td>2 1/4</td>
</tr>
<tr>
<td>200</td>
<td>1/4</td>
<td>1/2</td>
<td>1/2</td>
<td>1 1/4</td>
<td>2</td>
<td>3</td>
<td>4 1/4</td>
</tr>
<tr>
<td>300</td>
<td>1/4</td>
<td>1/2</td>
<td>3/4</td>
<td>1 3/4</td>
<td>3</td>
<td>4 1/2</td>
<td>6 1/2</td>
</tr>
<tr>
<td>400</td>
<td>1/2</td>
<td>3/4</td>
<td>1</td>
<td>2 1/4</td>
<td>4</td>
<td>6</td>
<td>8 1/2</td>
</tr>
<tr>
<td>500</td>
<td>1/2</td>
<td>3/4</td>
<td>1 1/4</td>
<td>2 3/4</td>
<td>4 3/4</td>
<td>7 1/2</td>
<td>10 3/4</td>
</tr>
<tr>
<td>1000</td>
<td>3/4</td>
<td>1 1/2</td>
<td>2 1/2</td>
<td>5 1/2</td>
<td>9 1/2</td>
<td>15</td>
<td>21 1/4</td>
</tr>
</tbody>
</table>

Notes:
1. See 4(d) and (e) of the guide material under §192.513 for an explanation of the calculations used to prepare this table.
2. The detectable pressure drop and detectable leak rate criteria should be based on the operator’s design and experience. For this example, the detectable leak rate \( RL = 5.0 \text{ scf/hr} \) and the detectable pressure drop \( Pd = 2 \text{ psi} \).
3. Note that a change in schedule number or wall thickness might affect the calculated duration.
4. Minimum test duration is chosen to be 1/4 hour, and calculated test durations have been rounded up in 1/4-hour increments.
5. For test durations beyond 24 hours, consider testing shorter sections to reduce the test duration.

TABLE 192.509i

§192.511
Test requirements for service lines.

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (69 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of
more than 40 p.s.i. (276 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with §192.507 of this subpart.


GUIDE MATERIAL

See 1(b), 3.1, and 4 of the guide material under §192.505; guide material under §§192.509, 192.515 and 192.517; and Guide Material Appendix G-192-10.

§192.513
Test requirements for plastic pipelines. [Effective Date: 07/13/98]

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 p.s.i. (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than three times the pressure determined under §192.121, at a temperature not less than the pipe temperature during the test.

(d) During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.


GUIDE MATERIAL

1 JOINTS

The joints in the plastic piping should be set, cured, or hardened before the test is initiated.

2 ODORANT

Odorant in the liquid form may be detrimental to certain kinds of plastic and should not be used to locate leaks in plastic pipelines.

3 TEMPERATURE LIMITATIONS

The operator should ensure that piping being tested does not exceed the maximum temperature at which it has been qualified as indicated by the marking on the pipe and fittings. The operator should consider the influence of ambient, test medium, and ground temperatures that can affect the pipe temperature during a test. Sunlight may significantly elevate the pipe temperature, and black plastic pipe
can exceed 140 °F (60 °C) temperature when exposed to direct sunlight. Some methods used to control or reduce temperatures during testing are as follows.
(a) Spraying the piping with water.
(b) Protecting the piping from direct sunlight.
(c) Placing the piping in the ditch to shade the piping.
(d) Performing the pressure test during the cooler parts of the day.

When addressing the requirements of §192.513(d), see guide material under §192.63 and Guide Material Appendix G-192-9A, Section 4.4.

4 TEST DURATION

(a) Establishing a test duration to determine potentially hazardous leaks in the segment being tested is based on analysis of multiple parameters, which include the following.
(1) Test medium used.
(2) Thermal effects.
(3) Volume of the test segment.
(4) Test pressure.
(5) Leak criteria.
(6) Instrumentation.
(b) When an analysis is performed, sufficient test durations can be established for various diameters of pipe at various lengths.
(c) If an analysis on the above parameters is not performed, examples of an approach to determine test durations for plastic service lines and mains at typical diameters and lengths are shown in Tables 192.513i and 192.513ii, respectively. These durations do not include the time to pressurize the test segments, time for temperature stabilization, and time for depressurizing the test segments. The test period should begin when the pressure of the test medium stabilizes.

Notes:
(1) The stabilization period depends on several factors, such as pipe diameter, pipe length, and temperature variation. Due to the circumferential expansion of plastic pipe when subjected to the initial pressurization and temperature variations, it is common for the pressure to drop by a few psig until it reaches a steady state.
(2) Temperature variations during the testing period could affect the gauge pressure and should be considered.
(d) The formula used in the Tables below is a generalization of Boyle’s gas law and is the basis for some operators’ test durations.

\[
\text{Test Duration (hours)} = \left[ \frac{(3.71 \times 10^{-4}) \times d^2 \times L \times P_d}{R_L} \right] \\
\text{Where:} \\
\quad d = \text{Internal diameter, inches} \\
\quad L = \text{Length of test section, feet} \\
\quad P_d = \text{Pressure drop, psi} \\
\quad R_L = \text{Leak rate, scf/hr}
\]

(e) In order to calculate the test duration, a pressure drop and leak rate criterion should be based on the operator’s design and experience. The following ranges are examples.
(1) Detectable pressure drop ($P_d$): 1 - 5 psi.
(2) Detectable leak rate ($R_L$): 1 - 5 scf/hr.
### Example Test Duration For Plastic Service Lines (minutes)

Criterion: Leak rate ($R_L$) = 1.5 scf/hr and pressure drop ($P_d$) = 2 psi

(Minimum test duration is chosen to be 5 minutes)

<table>
<thead>
<tr>
<th>Pipe Size</th>
<th>½ CTS</th>
<th>1 CTS</th>
<th>1¼ CTS</th>
<th>IPS 1¼</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wall Thickness (in.)</td>
<td>0.090</td>
<td>0.099</td>
<td>0.121</td>
<td>-</td>
</tr>
<tr>
<td>SDR</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>10</td>
</tr>
<tr>
<td>Pipe Size ID (in.)</td>
<td>0.44</td>
<td>0.91</td>
<td>1.12</td>
<td>1.34</td>
</tr>
<tr>
<td>Length (ft.)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>50</td>
<td>5</td>
<td>5</td>
<td>5</td>
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<td>100</td>
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<td>200</td>
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<td>10</td>
<td>15</td>
</tr>
<tr>
<td>300</td>
<td>5</td>
<td>10</td>
<td>15</td>
<td>20</td>
</tr>
<tr>
<td>400</td>
<td>5</td>
<td>10</td>
<td>15</td>
<td>25</td>
</tr>
<tr>
<td>500</td>
<td>5</td>
<td>15</td>
<td>20</td>
<td>30</td>
</tr>
</tbody>
</table>

Formula: Test Duration (minutes) = \[
\left(3.71 \times 10^{-4}\right) \times \left(d^2 \times L \times 2\right) \times 60 \div (1.5) = 2.97 \times 10^{-2} \left(d^2 \right) \left(L\right)
\]

Where:
- $d$ = Internal diameter, inches
- $L$ = Length of test section, feet

**Notes:**
1. The pressure drop and leak rate criteria should be based on the operator’s design and experience.
2. Calculated test durations have been rounded up in 5-minute increments.
Example Test Duration For Plastic Mains (hours)
Criteria: leak rate \( (R_L) = 5.0 \) scf/hr and pressure drop \( (P_d) = 2 \) psi
(Minimum test duration is chosen to be \( \frac{1}{4} \) hour)

<table>
<thead>
<tr>
<th>Pipe Size ID (in.)</th>
<th>Length (ft.)</th>
<th>IPS 2</th>
<th>IPS 3</th>
<th>IPS 4</th>
<th>IPS 6</th>
<th>IPS 8</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.93</td>
<td>50</td>
<td>1/4</td>
<td>1/4</td>
<td>1/4</td>
<td>1/4</td>
<td>1/2</td>
</tr>
<tr>
<td>1.93</td>
<td>100</td>
<td>1/4</td>
<td>1/4</td>
<td>1/4</td>
<td>1/2</td>
<td>1</td>
</tr>
<tr>
<td>1.93</td>
<td>200</td>
<td>1/4</td>
<td>1/4</td>
<td>1/2</td>
<td>1</td>
<td>1 1/2</td>
</tr>
<tr>
<td>3.65</td>
<td>300</td>
<td>1/4</td>
<td>1/2</td>
<td>3/4</td>
<td>1 1/2</td>
<td>2 1/4</td>
</tr>
<tr>
<td>5.37</td>
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<td>3</td>
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<tr>
<td>6.99</td>
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<td>3/4</td>
<td>1</td>
<td>2 1/4</td>
<td>3 3/4</td>
</tr>
<tr>
<td>5.37</td>
<td>1000</td>
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<td>1 1/4</td>
<td>2</td>
<td>4 1/2</td>
<td>7 3/4</td>
</tr>
<tr>
<td>5.37</td>
<td>2000</td>
<td>1 1/4</td>
<td>2 1/2</td>
<td>4</td>
<td>8 3/4</td>
<td>14 1/2</td>
</tr>
<tr>
<td>6.99</td>
<td>3000</td>
<td>1 3/4</td>
<td>3 3/4</td>
<td>6</td>
<td>13</td>
<td>21 3/4</td>
</tr>
</tbody>
</table>

Formula: \[ \text{Test Duration (hours)} = \left( \frac{(3.71 \times 10^{-4}) \times d^2 \times L \times (2)}{5} \right) = 1.48 \times 10^{-4} \times (d^2)(L) \]

Where:
- \( d \) = Internal diameter, inches
- \( L \) = Length of test section, feet

Notes:
1. The pressure drop and leak rate criteria should be based on the operator’s design and experience.
2. Calculated test durations have been rounded up in \( \frac{1}{4} \)-hour increments.
3. For test durations beyond 24 hours, consider testing shorter sections to reduce test duration.

TABLE 192.513ii

(f) When testing pipe of different sizes, the total test duration may be calculated by adding the test times given in Table 192.513ii. As an example, when testing 2000 feet of 4-inch and 1000 feet of 2-inch pipe together, the total test duration would be 4 hours for the 4-inch and \( \frac{3}{4} \) hour for the 2-inch pipe for a total of 4\( \frac{3}{4} \) hours.

5 SAFETY CONSIDERATIONS

See guide material under §192.515.
See 2 and 4 of the guide material under §192.505; guide material under §§192.515 and 192.517; and Guide Material Appendices G-192-9, G-192-9A, and G-192-10.

§192.515
Environmental protection and safety requirements. [Effective Date: 11/12/70]

(a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

GUIDE MATERIAL

1 GENERAL

See 3.1 and 4.1 of the guide material under §192.505.

2 SAFETY CONSIDERATIONS

2.1 General.
The following are other factors to be considered in the interest of safety.
(a) Locating personnel operating testing equipment at a safe distance from the pipeline facilities under test.
(b) Visually inspecting temporary piping, closures, and other equipment used in connection with the test, both prior to the application of the test pressure and at appropriate intervals during the test, to ensure soundness.
(c) Providing for supports or anchors, as required, to prevent excessive stress levels in the test piping and the piping under test.
(d) Locating blowdown devices in a manner that will divert the gas and the test medium away from electrical conductors.
(e) Filling and purging the facilities in a manner consistent with good purging principles, taking into consideration the following.
    (1) Compliance with the requirements in §192.629.
    (2) Minimizing entrapment of air or gas in the pipeline segment to be subjected to hydrostatic test by inserting a sphere or other suitable device ahead of the test medium while filling, or by installing vents at high spots.
    (3) Wind direction and velocity.
(f) Communications between the supervisor in charge and the line surveillance teams, pressure control and monitor stations, blowdown points and other stations or personnel responsible for various aspects of the work.
(g) Ready availability of fire extinguishers, breathing apparatus, safety harnesses, ear protection
devices, combustible gas detectors, oxygen deficiency indicators and other such equipment in the work area.

(h) Distribution of a written test procedure (including the applicable portions of Guide Material Appendix G-192-12) to employees or contractor personnel or both. The procedure should be reviewed with all persons involved in conducting the test prior to commencing any work and should include actions to be taken in the event of a test failure.

2.2 *Tests in excess of 50 percent SMYS.*

When the test will result in hoop stresses in excess of 50% SMYS, particularly in uprating facilities, each operator should consider the following precautionary measures to ensure that the test area is kept clear of persons not directly engaged in the testing operation.

(a) Placing caution signs or barriers along the pipeline route wherever deemed appropriate, such as at roads and public corridors. These should be supplemented by security patrols or guards or both in residential areas, industrial areas and at river crossings.

(b) Aerial surveillance of the pipeline route, when practical, to monitor activity in the test area when testing with natural gas, inert gas or air.

(c) Notifying parties located in the general vicinity of the pipeline to avoid the test area during the period of the test.

(d) Notifying law enforcement agencies, fire departments, state and county highway departments, railroad and utility companies with facilities in the test area and, as applicable, airport operators regarding the scope and period of the test.

(e) When the test is being conducted in high exposure areas, consideration should be given to the following.

   (1) Scheduling the test at a time to minimize public exposure.

   (2) Limiting the length of the test section to minimize potential hazards.

2.3 *Tests in excess of 90 percent SMYS.*

When the test pressure will produce a hoop stress in excess of 90% of SMYS, the following additional precautions may be considered to minimize the risk to occupants of buildings in close proximity to the pipeline.

(a) Using pre-tested pipe.

(b) Pre-testing the segment.

(c) Using energy absorbing devices (e.g., sandbag barriers, backfill, piling, and walls).

3 **HAZARDS ASSOCIATED WITH FILLING AND DEWATERING PIPELINES FOR HYDROSTATIC TESTING**

(a) During the filling and dewatering processes, significant and sudden variations in pressure may occur within the pipeline and the temporary filling and dewatering piping. These variations can be caused by changes in velocity of the pig passing through bends in the pipeline or of the pig and water due to changes in pipeline elevation. Compressed air escaping around a pig can also create a source for stored energy within the pipeline. The release of this stored energy, as well as surges transferred from the pipeline to the temporary filling and dewatering piping, can result in pipe movement.

(b) When conducting a hydrostatic test, the following should be considered when filling and dewatering pipes.

   (1) Prepare a detailed test plan that includes the required equipment, test duration, and test pressure.

   (2) Conduct training for the individuals involved with the test that includes a review of the test and dewatering plan, instructions on the filling/dewatering system installation and techniques, and proper coupling and anchoring methods.

   (3) Perform an engineering analysis of the existing and temporary piping systems to identify the forces that could adversely affect the integrity of the pipeline, the integrity of temporary fill piping, or the integrity and stability of the drainage components, such as excessive or variable pressures caused by a stuck pig or leaks. An engineering analysis may consist of the following.
(i) Designing the temporary piping system within the parameters of the hydrostatic pressure test. Consider factors such as the diameter and pressure rating of the temporary piping system (including couplings and fittings), the joining method, and the piping geometry.

(ii) Accounting for hydrostatic head pressure caused by changes in elevation.

(iii) Considering pressure variations or thrust due to changes in direction at bends, elbows, and dead-ends.

(iv) Determining the proper joining method for the temporary piping system.

(4) Develop installation techniques that address forces expected during the filling, testing, and dewatering operations. Those techniques would include effective anchoring systems that prevent pipe movement, separation, or whipping. Piping components (e.g., couplings, flanges, valves) should be free of damage and installed in accordance with manufacturer’s instructions.

(5) Inspect temporary pipe, couplings, and fittings to ensure they are in good condition and rated for the pressure and temperature conditions specified for the test.

(6) Ensure that anchoring and support systems are installed in accordance with the plan.

(7) Control access to the area around the test site by establishing a limited-access zone to keep out persons not involved with the test.

(c) For additional background information on this subject, see OPS Advisory Bulletin ADB-04-01 (69 FR 58225, Sept. 29, 2004; reference Guide Material Appendix G-192-1, Section 2).

4 ENVIRONMENTAL CONSIDERATIONS

Each operator, in fulfilling the local, state, and federal environmental regulations with respect to the disposal of the test medium, should, among other things, give consideration to the following.

(a) Selecting water from satisfactory sources.

(b) Mitigating erosion and flooding of the area where the water is being discharged.

(c) Using filters, impoundment facilities or other appropriate methods to ensure that the atmosphere and the surface waters are not unnecessarily contaminated by the products being discharged.

(d) Using silencers, during the blowdown operation, where sound might be generated which is objectionable to area residents.

(e) Scheduling and locating the blowdown to minimize public objection to the noise generated.

§192.517 Records.

[Effective Date: 10/15/03]

(a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§192.505 and 192.507. The record must contain at least the following information:

(1) The operator’s name, the name of the operator’s employee responsible for making the test, and the name of any test company used.

(2) Test medium used.

(3) Test pressure.

(4) Test duration.

(5) Pressure recording charts, or other record of pressure readings.

(6) Elevation variations, whenever significant for the particular test.

(7)Leaks and failures noted and their disposition.

(b) Each operator must maintain a record of each test required by §§192.509, 192.511, and 192.513 for at least 5 years.

[Amndt. 192-93, 68 FR 53895, Sept. 15, 2003]
GUIDE MATERIAL

(a) In addition to the requirements of §192.517(a), records of a pressure test should include the following.

(1) Start and completion times of the test.

(2) Name of the person responsible for performing the test and the person who approved the test, if different.

(3) A detailed description of the segment of pipeline and associated components that were tested, which should include:
   (i) For station piping, a diagram of the station that identifies the location of the tested segment;
   (ii) For a pipeline, the segment length using mile markers, stationing, or other location description;
   (iii) For pipeline components, the type, size, locations, and pressure ratings; and
   (iv) For all tested pipe, the following.
       (A) Outside diameter.
       (B) Wall thickness.
       (C) Pipe grade or designation.
       (D) Pipe material.
       (E) Joint types.
       (F) Seam type.

(b) Records of a successful hydrostatic pressure test might include the following in addition to that listed under (a) above.

(1) Minimum and maximum elevation values, including the calculated test pressure, measured test pressure, or both at the control point as well as the highest and lowest points.

(2) Temperatures recorded throughout the duration of the test:
   (i) Ambient air.
   (ii) Underground (restrained) piping.
   (iii) Aboveground (unrestrained) piping.

(3) Liquid volume injected, withdrawn, or both, during the test.

(4) Pressure versus volume plot.

   Note: To confirm that the test did not reveal any leaks or yield the pipe, taking into consideration the thermal effects on unrestrained piping throughout the duration of the test.

(c) For pre-November 12, 1970 pipelines, operators might not have pressure test records that meet all of the current requirements under §192.517(a). In the event a pressure test was conducted prior to that date, an operator may consider several different types of records that verify a pressure test was conducted. Preferably, those records would include a date and signature of the individual who witnessed the test. Any one or combination of the following records may be considered.

(1) Test pressure records, including charts or other forms indicating pressure recordings.

(2) Job-specific pressure test plan and procedure.

(3) Notation of completion of pressure test requirements on as-built drawings.

(4) Field notes or log books with details of testing.

(5) An operator form with details of the pressure test.

(6) Other documents that the operator deems appropriate per their specific standards.

(d) For tests conducted under §§192.509, 192.511, or 192.513, records are required to show that the tests have been conducted. The date, location of the test, and the test pressure applied may be sufficient documentation. Additional information may be included at the discretion of the operator.

(e) For segments of steel service line stressed to 20% or more of SMYS (§192.511(c)), records are required to document testing in accordance with §192.507.

(f) For a non-welded joint used to tie in a pipeline, the operator should have a record demonstrating that a leak test was performed at not less than the operating pressure (see §192.503(d)).
SUBPART K
UPRATING

§192.551
Scope.

[Effective Date: 11/12/70]

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

GUIDE MATERIAL
No guide material necessary.

§192.553
General requirements.

[Effective Date: 10/15/03]

(a) Pressure increases. Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

1. At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.
2. Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

(b) Records. Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.

(c) Written plan. Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.

(d) Limitation on increase in maximum allowable operating pressure. Except as provided in §192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under §§192.619 and 192.621 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, the MAOP may be increased as provided in §192.619(a)(1).

1 GENERAL CONSIDERATIONS

In fulfilling the requirements of Subpart K (and any state and local requirements for uprating), it is recommended that the written plan required by §192.553(c) include, as applicable, the following.

(a) The purpose of pressure increase.
(b) The amount of increase and the proposed MAOP.
(c) The location class(es) of the segment being uprated.
(d) A review of the requirements in §§192.619, 192.621, and 192.623 to ensure that the proposed new maximum allowable operating pressure may be adopted.
(e) A review of the overpressure protection requirements in §§192.195, 192.199, and 192.201.
(f) A review to ensure proper capacity, set points, and function of the devices in accordance with §§192.739, 192.741, and 192.743.
(g) A description of the facility. This can be a schematic map to clearly define the pipeline segment to be uprated and all adjacent pipelines and mains. This map should indicate the following.
   (1) Construction dates.
   (2) Size, wall thickness, and grade of pipe.
   (3) Laterals, side connections and other appurtenances.
(h) A review of the uprating's effect on the operator's integrity management program and the control room management procedures.
(i) A schedule of proposed work. The steps to be taken to accomplish the uprating should be listed.
(j) The definition and assignment of responsibility to complete the various phases of a line uprating including a check and verification procedure which will ensure that all steps have been completed in compliance with the federal standards before higher pressure is introduced into the system to be uprated.
(k) The sequence of steps necessary to isolate adjacent piping from the system to be uprated. Remaining connections to adjacent piping, which will operate at a lower pressure, should be at points where pressure reducing equipment has been installed in compliance with §§192.195 and 192.201.
(l) A determination that adequate pressure can be maintained in adjacent systems when the section to be uprated is isolated. If additional interconnections with a higher operating pressure system are required to maintain the lower pressure system, these connections should conform to the federal standards.
(m) A procedure for the instruction of all personnel involved in the uprating procedure to ensure familiarity with the plan.
(n) The notification of all affected customers sufficiently in advance to ensure maximum accessibility of premises during the uprating operation.
(o) The alterations to pressure regulation and pressure relief facilities necessary to meet the requirements of §§192.195 and 192.201.
(p) The precautions to be taken to protect employees and the general public during the uprating operation.
(q) Provision for monitoring pressure in adjacent facilities during uprating. This should be done to ensure that there are no connections, from the higher pressure system to a lower pressure system, that do not have pressure reducing equipment conforming to the federal standards.
(r) Provision for a final leak survey to confirm the integrity of the facility after uprating is completed.

2 DISTRIBUTION SYSTEMS

The following additional items, as applicable, are recommended for the written plans of uprating projects in distribution systems.

(a) A list of locations where sectionalizing valves are to be installed to meet the requirements of §192.181.
(b) A list of service lines on the main segments to be uprated.
(c) Provision for checking in the field the source of gas supply for all properties:
   (1) Within the boundaries of the affected area.
   (2) Adjoining the boundaries of the affected area. This is particularly significant for low-pressure
       service lines that have no service regulators.
   (d) A list of those inactive lines, connected to the segment, which will be abandoned in accordance with
       §192.727.
   (e) A list of service-line valves to be installed to meet the requirements of §§192.363 and 192.365 (if
       applicable).

§192.555

Uprating to a pressure that will produce a hoop stress
of 30 percent or more of SMYS in steel pipelines.

[Effective Date: 11/12/70]

(a) Unless the requirements of this section have been met, no person may subject any segment
of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of
SMYS and that is above the established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable
operating pressure the operator shall —
   (1) Review the design, operating, and maintenance history and previous testing of the
       segment of pipeline and determine whether the proposed increase is safe and consistent with the
       requirements of this part; and
   (2) Make any repairs, replacements, or alterations in the segment of pipeline that are
       necessary for safe operation at the increased pressure.

(c) After complying with paragraph (b) of this section, an operator may increase the maximum
allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the
highest pressure that is permitted under §192.619, using as test pressure the highest pressure to
which the segment of pipeline was previously subjected (either in a strength test or in actual
operation).

(d) After complying with paragraph (b) of this section, an operator that does not qualify under
paragraph (c) of this section may increase the previously established maximum allowable operating
pressure if at least one of the following requirements is met:
   (1) The segment of pipeline is successfully tested in accordance with the requirements of
       this part for a new line of the same material in the same location.
   (2) An increased maximum allowable operating pressure may be established for a segment
       of pipeline in a Class 1 location if the line has not previously been tested, and if —
       (i) It is impractical to test it in accordance with the requirements of this part;
       (ii) The new maximum operating pressure does not exceed 80 percent of that allowed
           for a new line of the same design in the same location; and
       (iii) The operator determines that the new maximum allowable operating pressure is
           consistent with the condition of the segment of pipeline and the design requirements of this part.

(e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d) (2) of this
section, the increase in pressure must be made in increments that are equal to —
   (1) 10 percent of the pressure before the uprating; or
   (2) 25 percent of the total pressure increase, whichever produces the fewer number of
       increments.
GUIDE MATERIAL

1 REVIEW PRIOR TO INCREASING OPERATING PRESSURE (§192.555(b)(1))

The following list contains items that an operator should consider when performing the required review.

1.1 Design review.
   (a) Present class location.
   (b) Adequacy of the original design, and of any change made to the original design during or subsequent to the original installation, for service at the proposed maximum allowable operating pressure. Particular attention should be paid to the following.
      (1) Material identification as shown on operator records.
      (2) Use of mill or other material analysis or inspection reports, or field inspections to resolve discrepancies or determine unknown values.
      (3) Pressure/temperature ratings of components, especially rated pressure at the limiting temperature of valves, regulators, etc.
      (4) Longitudinal joint factor ($E$) of pipe. See §192.113.
      (5) End closures.
      (6) Flexibility of piping arrangements.

   For pipe which design pressure cannot be calculated because one or more of the variables for determining the design pressure in §192.105 is unknown, a value may be determined in accordance with §192.619(a)(1).
   (c) Present right-of-way conditions such as the following.
      (1) Buried pipelines that have become exposed.
      (2) Pipeline segments crossing or with in the right-of-way of public roads.
      (3) Crossings exposed to heavy vehicular traffic.
      (4) Pipeline segments subject to additional mechanical stress due to support settlement or other factors.
      (d) Adequacy of mill tests on pipe that has not been tested after installation to at least 118% of the proposed maximum allowable operating pressure.
      (e) Characteristics, at the proposed maximum allowable operating pressure, of existing regulators, flow controllers and other instruments.
      (f) Need, for operation at the proposed maximum allowable operating pressure, for additional flow control, pressure limiting, or shut-off components.
      (g) Adequacy of connected facilities.

1.2 Operating history review.
   (a) Date of original construction (before or after September 12, 1970).
   (b) Operating pressures and temperatures experienced by the pipeline segment.
   (c) For segments of pipeline constructed before September 12, 1970, records of an operating pressure appropriate for use as a test pressure as permitted under §192.555(c).
   (d) Leakage history records.
   (e) Corrosion records.
   (f) Cathodic protection (CP).
      (1) Date installed.
      (2) Level maintained.
      (3) Substantial changes in CP requirements.
   (g) Unusual operating conditions.
   (h) Failure and emergency reports including the possibility of recurrence because of the increased pressure.
(c) An analysis of stresses imposed on cast iron and ductile-iron pipe wherein operators commonly use
the design criteria addressed in §192.557(d).

(d) An analysis of the original design and construction of the pipeline and the ability to safely contain the
higher pressure. Consideration should be given to the possibility that the increased pressure may
cause leaks.

(e) A review of leakage, corrosion, operating pressure, and maintenance history to ascertain the
present condition of facilities.

(f) An analysis of the effect of the ultimate separation and uprating on adjoining facilities.

(g) A review of General Considerations in 1 of the guide material under §192.553.

1.2 Additional consideration.

(a) An analysis should be made to confirm that the proposed MAOP is in accordance with the
requirements as set forth in §192.553(d).

(b) For cast iron pipe, see Guide Material Appendix G-192-18.

2 WORK PRELIMINARY TO UPRATING

2.1 Leak survey.
A leak survey may be required by §192.557(b)(2). Types of leakage surveys are described in Guide
Material Appendix G-192-11 (Natural Gas) and Guide Material Appendix G-192-11A (Petroleum Gas).

2.2 Changes to the system.
Repairs, replacements, or other alterations necessary for the safe operation of both the system to be
uprated and the existing system should include the following.

(a) Installation of anchors or joint reinforcement as required in §192.557(b)(4).

(b) Renewal of gas service lines where warranted.

(c) Installation of service line shut-off valves where required and in accordance with §§192.363 and
192.365.

(d) Installation of service regulators where required and in accordance with §§192.197, 192.353,
192.355, and 192.357.

(e) Consideration of the adequacy of existing service regulators and their characteristics with present
orifice sizing at the proposed pressure levels.

2.3 Monitoring.
Provision should be made for monitoring field pressures prior to and during uprating to ensure the
integrity of both the system to be uprated and the adjacent systems that might be affected by the
uprating.

2.4 Interface.
The necessary field work should be performed to provide positive control to avoid overpressuring the
sections of the systems that are not being uprated. Control procedures may involve actual physical
separation of sections, installation of regulator equipment that is properly operated and set to control at
the proper pressure, or other effective means of separation.

2.5 Customer notification.
Customers should be notified of planned interruptions of gas service.

3 INCREASING PRESSURE

3.1 Communications.
Lines of communication should be established between all control points.

3.2 Isolation.
The system should be isolated from all lower pressure systems.
3.3 Pressure regulation.
   The valve to each service regulator should be closed or the operation of each service regulator should
   be monitored as the pressure in the main is increased.

3.4 Leak check.
   See §192.553(a)(1).

3.5 Leak repairs.
   See §192.553(a)(2).

3.6 Monitoring.
   The pressure in adjacent facilities should be monitored during the uprating procedure to establish:
   (a) That no connection is acting as a source of unregulated gas from the higher pressure segment to
       the lower pressure system; and
   (b) The adequacy of the remaining lower pressure system at points of separation and other locations.

3.7 Final leak survey.
   After the uprating is completed, a final leak survey should be made to confirm the integrity of the
   facilities. Necessary leak repairs should be made.

4 RECORDS

   The records of investigations, the work, and the testing should be forwarded to the proper department
   for retention for the life of the facility.
3 REPORTING (§192.612(c)(1))

In addition to the reporting requirements of §192.612(c)(1), an operator should also consider including the following.
(a) Latitude and longitude of the pipeline end points.
(b) Offshore area name.
(c) Offshore block number.
(d) Name of water body.
(e) Name of parish or county.
(f) Other pertinent information.

4 REMEDIAL ACTION

If an operator is unable to meet the deadline for remediation, the required notification to OPS should be in writing.

§192.613
Continuing surveillance.
[Effective Date: 11/12/70]

(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §192.619(a) and (b).

GUIDE MATERIAL

1 GENERAL

Continuing surveillance should be conducted to identify any pipeline facilities experiencing abnormal or unusual operating and maintenance conditions. This may be accomplished by the following.

(a) Periodic visual inspection of facilities to identify items such as the following.
   (1) Changes of population densities.
   (2) Effects of exposure or movement of pipeline facilities.
   (3) Changes in topography that may have an effect on pipeline facilities.
   (4) Potential for, or evidence of, tampering, vandalism, or damage.
   (5) Effects of encroachments on pipeline facilities.
   (6) Potential for gas migration through air intakes into buildings from vaults and pits.
   (7) Specific circumstances relating to patrolling and leakage. See guide material under §§192.705, 192.706, 192.721, and 192.723.
   (8) Potential for, or evidence of, soil or water accumulation in vaults or pits.
   (9) Potential for, or evidence of, excavation activity. If evidence of an excavation is found near a transmission pipeline covered segment, the location must be examined in accordance with §192.935(b)(1)(iv).
   (11) Potential for, or evidence of, flooding. See 6 below.
(b) Periodic review and analysis of records, such as the following.
   (1) Patrols.
   (2) Leak surveys.
   (3) Valve inspections.
   (4) Vault inspections.
   (5) Pressure regulating, relieving, and limiting equipment inspections.
   (6) Corrosion control inspections.
   (7) Facility failure investigations.

Anomalies discovered should be evaluated, and those determined to present potential safety concerns should be scheduled for remediation and communicated to appropriate integrity management personnel.

2 CAST IRON PIPELINES

For cast iron pipelines, see Guide Material Appendix G-192-18.

3 PE PIPELINES

(a) Some PE materials manufactured before 1982 have a lower resistance to the effects of induced stresses and are subject to brittle-like cracking under certain in-service conditions (e.g., rock impingement, squeeze-offs, severe bending moments). Brittle-like cracking is characterized by a part-through crack initiating in the pipe wall followed by slow crack growth causing failure. These failures result in a tight slit-like opening and a gas leak. This older generation of PE may have leak-free performance for a number of years before brittle-like cracks occur. An increase in the occurrence of leaks is typically the first indication of a brittle-like cracking problem.

(b) PE materials that are most known for this failure mode include the following.
   (1) Century Utility Products, Inc. products.
   (2) Low-ductile inner wall PE 2306 "Aldyl A" pipe manufactured by DuPont Company during 1970 through 1972, generally NPS 1 ¼ to NPS 4. To determine if the "Aldyl A" pipe has low-ductile inner wall, see 3(f) below.
   (3) PE gas pipe designated PE 3306.
   (4) DuPont PE tapping tees with DuPont Delrin® polyacetal (homopolymer) inserts (see 3(g) below).
   (5) Plexco PE service tees with Celanese Celcon® polyacetal (copolymer) caps (see 3(h) below).

(c) Conditions that may cause these types of materials to fail prematurely include the following.
   (1) Inadequate support and backfill during installation.
   (2) Tree root or rock impingement.
   (3) Shear and bending stresses due to differential settlement resulting from factors such as:
      (i) Excavation in close proximity to PE piping.
      (ii) Directional drilling in close proximity to PE piping.
      (iii) Frost heave.
   (4) Bending stresses due to pipe installations with bends exceeding recommended practices.
   (5) Stresses where the pipe has been squeezed off.

(d) Each operator that has these older PE pipelines should consider the following practices.
   (1) Review system records to determine if any known susceptible materials have been installed in the system.
   (2) Perform more frequent inspection and leak surveys on systems that have exhibited brittle-like cracking failures of known susceptible materials.
   (3) Collect failure samples of PE piping exhibiting brittle-like cracking.
   (4) Record the print line from any piping that has been involved in a failure. The print line information can be used to identify the resin, manufacturer, and year of manufacture for plastic piping.
Additional guidance on mitigation methods may be found in ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas," which documents a joint industry project.

4.2 References.
(a) ASME B31.8S, Appendix A3 and Table 4 (see §192.7).
(b) ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas."
(c) NACE Publication 35103, "External Stress Corrosion Cracking of Underground Pipelines."
(d) NACE SP0204, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology."
(f) OPS Advisory Bulletin ADB-03-05 (68 FR 58166, Oct. 8, 2003; see Guide Material Appendix G-192-1, Section 2).
(g) OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study," Michael Baker, Jr., Inc., January 2005.
(h) PRCI L52047, "Pipeline Repair Manual."

5 THREADED JOINTS

Operators that have threaded joints in underground gas systems may want to determine if increased surveillance is warranted. Factors that could be considered include wall thickness, leak history, susceptibility to corrosion, settlement, frost-induced movement, and third-party damage.

6 SEVERE FLOODING

Severe flooding can adversely affect the safe operation of a pipeline. Operators should consider the following actions in areas prone to, or previously affected by, flooding.
(a) Identify pipeline facilities that are in the flood plain, such as overlaying 100-year flood elevations on GIS pipeline maps.
(b) For buried pipelines, consider terrain and vegetation conditions that can cause severe scouring of the watercourse. Such conditions could include burned areas subject to soil erosion and long-term buildup of debris and vegetation along the watercourse.
(c) For aerial or aboveground pipeline crossings, consider the potential for the following.
   (1) Scouring of deadman anchors and tower foundations on cable-supported pipelines and traffic or pedestrian bridges.
   (2) Floating debris impacting the pipeline and its supports beneath or on the upstream side of traffic or pedestrian bridges.
(d) Extend regulator vents and relief stacks above the level of anticipated flooding, as appropriate.
(e) Determine if facilities that are normally above ground (e.g., valves, regulators, relief devices) could become submerged and then have a potential for being struck by vessels or debris, and consider protecting or relocating such facilities.
(f) For additional information, see OPS Advisory Bulletin ADB-2016-01 (81 FR 2943, Jan 19, 2016; see Guide Material Appendix G-192-1, Section 2).

7 SERVICE LINES UNDER BUILDINGS

Buried and uncased service lines discovered under buildings should be moved to locations no longer beneath the building or reinstalled under the building in accordance with the requirements of §192.361. In instances involving mobile homes, it may be possible to have the home relocated away from the service line. See guide material under §192.361.
8 INTEGRITY MANAGEMENT CONSIDERATIONS

Conditions or information discovered that could affect the integrity of a pipeline should be reported to the appropriate integrity management and operating personnel.

§192.614 Damage prevention program. [Effective Date: 07/20/98]

(a) Except as provided in paragraphs (d) and (e) of this section, each operator of a buried pipeline shall carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purpose of this section, the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations.

(b) An operator may comply with any of the requirements of paragraph (c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) of this section.

(1) The state has adopted a one-call damage prevention program under §198.37 of this chapter; or
(2) The one-call system:
   (i) Is operated in accordance with §198.39 of this chapter;
   (ii) Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and
   (iii) Assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.
(2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program:
   (i) The program's existence and purpose; and
   (ii) How to learn the location of underground pipelines before excavation activities are begun.
(3) Provide a means of receiving and recording notification of planned excavation activities.
(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.
(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.
(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:
   (i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and
priority than protection of property.

(e) Damage prevention.

See 2.5 of the guide material under §192.614.

2.4 Additional information.

Distribution system operators may choose to include additional messages for 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.
(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.

2.5 Message delivery methods.

Guidance is provided in API RP 1162, Section 5 for several delivery methods and tools available for communicating with the stakeholder audiences. See 2.4 of the guide material under §192.614 for additional information regarding delivery methods for excavators and the affected public. However, the operator is required by §192.616(c) to justify in its program or procedural manual if it does not follow the general program recommendations of API RP 1162 regarding message delivery methods.

3 LANGUAGE

The following may provide indications of languages in addition to English to consider when conducting public education programs.

(a) Languages prescribed by state or local governments.
(b) Commercial non-English radio, television, and print media.
(c) U.S. Census data.

4 REFERENCES

(a) Information regarding public education programs, such as FAQs and Workshops, is available at primis.phmsa.dot.gov/comm/PublicEducation.htm.
(b) OPS Advisory Bulletins (see Guide Material Appendix G-192-1, Section 2) as follows.
   (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.

[Effective Date: 11/12/70]

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.
GUIDE MATERIAL

1 GENERAL

(a) Data on all failures and leaks should be compiled to support compliance with §192.613. A failure investigation should be performed to determine the cause of the failure and minimize the possibility of a recurrence.

(b) For information on failures of PE pipe, see 3 of the guide material under §192.613.

(c) For information on reporting failures of mechanical fittings, see guide material under §191.12.

2 TYPES AND NATURE OF FAILURES THAT SHOULD BE ANALYZED

Failure investigation should be conducted for incidents as defined in §191.3. An operator should also consider investigating any other failure that enables the operator to establish patterns that might be occurring on its pipeline system. For examples, see guide material under §192.613.

3 FAILURE INVESTIGATION

(a) Failure investigation and subsequent analysis should determine the root cause(s) of the failure. The investigation may be as simple as assembling an internal review group or as complex as conducting a full-scale failure investigation with laboratory analysis of a failed component. The information for completing a 30-day incident report form contained in Part 191 may constitute an adequate analysis of a reportable failure or leak. See §§191.9 and 191.15.

(b) The general process for performing root-cause analysis is as follows.

(1) Assemble the review team.

(2) Define the problem and gather data and documentation.

(3) Identify factors that contributed to the problem (i.e., causal factors).

(4) Find the root cause for each causal factor, such as people, equipment, material, process, or outside influence.

(5) Develop and assign recommendations.

(6) Distribute recommendations and review the operator’s procedures.

(7) Implement the recommendations.

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 of evidence.

5.2 Other failures.

Gather sufficient data to complete the general process for performing root-cause analysis. See 3 above.
Pipeline segment | Pressure date | Test date |
--- | --- | ---
— Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006. | March 15, 2006, or date line becomes subject to this part, whichever is later. | 5 years preceding applicable date in second column. |
— Onshore transmission line that was a gathering line not subject to this part before March 15, 2006. | | |

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).


GUIDE MATERIAL

(a) Before adjusting the operation of a pipeline by increasing pressure within the limits of the pipeline segment's MAOP, but substantially above a historical long-term operating pressure, the operator should consider a review of the operating, maintenance, and testing history for the segment. See guide material under §§192.555 and 192.557. Pressure should be increased gradually at an incremental rate. The operator should consider conducting a leak survey when the pressure increase is concluded.

§192.620
Alternative maximum allowable operating pressure for certain steel pipelines.
[Effective Date: 10/01/15]

(a) How does an operator calculate the alternative maximum allowable operating pressure? An operator calculates the alternative maximum allowable operating pressure by using different factors in the same formulas used for calculating maximum allowable operating pressure under §192.619(a) as follows:

(1) In determining the alternative design pressure under §192.105, use a design factor determined in accordance with §192.111(b), (c), or (d) or, if none of these paragraphs apply, in accordance with the following table:

<table>
<thead>
<tr>
<th>Class Location</th>
<th>Alternative Design Factor (F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.80</td>
</tr>
<tr>
<td>2</td>
<td>0.67</td>
</tr>
<tr>
<td>3</td>
<td>0.56</td>
</tr>
</tbody>
</table>

(i) For facilities installed prior to December 22, 2008, for which §192.111(b), (c), or (d) applies, use the following design factors as alternatives for the factors specified in those paragraphs: §192.111(b) — 0.67 or less; 192.111(c) and (d) — 0.56 or less.

(ii) [Reserved]

(2) The alternative maximum allowable operating pressure is the lower of the following:

(i) The design pressure of the weakest element in the pipeline segment, determined under subparts C and D of this part.

(ii) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction by a factor determined in the following table:

<table>
<thead>
<tr>
<th>Class Location</th>
<th>Alternative Test Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.25</td>
</tr>
<tr>
<td>2</td>
<td>1.50</td>
</tr>
<tr>
<td>3</td>
<td>1.50</td>
</tr>
</tbody>
</table>

¹For Class 2 alternative maximum allowable operating pressure segments installed prior to December 22, 2008 the alternative test factor is 1.25.

(b) When may an operator use the alternative maximum allowable operating pressure calculated under paragraph (a) of this section? An operator may use an alternative maximum allowable operating pressure calculated under paragraph (a) of this section if the following conditions are met:

(1) The pipeline segment is in a Class 1, 2, or 3 location;

(2) The pipeline segment is constructed of steel pipe meeting the additional design requirements in §192.112;

(3) A supervisory control and data acquisition system provides remote monitoring and control of the pipeline segment. The control provided must include monitoring of pressures and flows, monitoring compressor start-ups and shut-downs, and remote closure of valves per paragraph (d)(3) of this section;
(b) Extremely saturated soils that produce buoyant forces on pipelines.
   (1) River and stream crossings.
   (2) Lowlands, floodplains, and swamps.
   (3) Coastal areas prone to tidal surges from hurricanes or tropical storms.
(c) Areas susceptible to frost heave.
(d) High expansive or unstable soils (e.g., some clays or manmade soils).
(e) Locations with known geologic conditions that contribute to instability (e.g., karst topography, sinkholes, underground mining, other subsidence areas).

11.3 Fault zones.
The following should be considered in evaluating an active or known fault zone.
(a) Location of earthquake fault lines.
(b) Previous earthquake activity.
(c) Probability of future earthquake activity along fault.
(d) Analyses of leaks or damage attributable to earthquake activity.

11.4 Year of installation.
Older pipeline facilities were constructed with materials and techniques that are generally not equivalent to modern facilities in terms of strength and integrity. The risk attributable to weather-related and outside force threats may be commensurate with the age of the pipeline facilities. If the installation data is not known, conservative estimates of the installation year can be used.

11.5 Pipe parameters.
The following pipe parameters are factors in determining operating hoop stress.
(a) Pipe grade.
(b) Wall thickness.
(c) Outside pipe diameter.

ASME B31.8S, Appendix A9.2(g) states that the sum of all pipe stresses (e.g., longitudinal, hoop stress, bending, overburden) is not to exceed 100% SMYS. If any of the pipe parameters are not known, conservative estimates of the missing data should be used.

11.6 Other considerations.
(a) Weather-related conditions.
   Excessive loading from weather-related conditions that are likely to occur (see guide material under §§192.317 and 192.615).
   (1) Tornadic activity or high winds.
   (2) Heavy snow or ice loading.
   (3) Lightning strikes.
   (4) Wild (or other) fires.
   (5) Flooding (see 6 of guide material under §192.613).
(b) Operations and maintenance records.
   Operators should review operations and maintenance records (e.g., patrolling data) to determine whether extreme loading conditions are present on their pipelines. Information may also be found in incident reports, safety-related condition reports, leakage information, abnormal operations, and other failure investigations required by §192.617.
(c) Fatigue cracking from improper loading of pipe on railcars.
(d) See 15.3.2 below.

12 PLASTIC TRANSMISSION PIPELINES

12.1 General.
The following guide material is generally repetitive of Sections 6 through 11 above. The portions of those sections that are also applicable to plastic pipelines have been consolidated here for the
convenience of operators with plastic transmission pipelines. For additional guidance on identifying threats to plastic pipelines, see Guide Material Appendix G-192-8, Section 4. Although that appendix is directed at distribution facilities, the threat identification process may be applied to plastic transmission pipelines.

12.2 Identification of threats to plastic pipelines.
Section 192.917 requires operators to address all potential threats to pipeline integrity. Threats for plastic pipelines may be grouped into the following categories.

(a) Time-dependent threats.
Time-dependent threats are those that may grow more severe over time. Analysis based on sound engineering practices may be used to help predict when these threats might become critical. For plastic pipelines, these threats include the following.

(1) Crack propagation.
(2) Degradation due to exposure to liquid hydrocarbons.

(b) Stable threats.
A threat that has passed post-construction testing may be considered stable. However, stable threats may need to be reconsidered as external factors (e.g., external loading, temperature changes, pressure changes) act upon the pipeline. Stable threats include the following.

(1) Manufacturing defects.
(2) Construction defects.
(3) Equipment failures.

(c) Time-independent threats.
Time-independent threats are generally associated with events that may take place along the pipeline segment and can happen at any time. These threats include the following.

(1) Excavation damage.
(2) Incorrect operations (includes human error).
(3) Weather-related and outside force.

(d) Other threats.
Section 192.917 also requires operators to analyze the pipeline for other threats that may not fit into one of the above categories. See 12.9 below.

12.3 Manufacturing threats.
This threat refers to defects of the pipe or fittings that are associated with the manufacturing process. Additional guidance for manufacturing considerations related to plastic pipelines can be found in guide material under §§192.121, 192.123 and 192.613 and OPS Advisory Bulletins (ADBs). See 15.2 below for a list of applicable ADBs.

(a) Potential manufacturing threats.

(1) Identification of a manufacturing defect may be accomplished as follows.

(i) By observations of pipe surfaces and fittings during normal construction, operation, and maintenance activities.
(ii) Through failure analysis, such as after incidents.
(iii) During review of prior integrity assessment results.
(iv) By review of Plastic Pipe Database Committee (PPDC) reports. See 15.2.2 below.

(2) Some examples of pipe defects include the following.

(i) Errors or upsets in material resin formulation.
(ii) Wall thinning or scoring.
(iii) Fiberglass reinforced plastic (FRP) delamination.
(iv) Inclusions (e.g., impurities within the pipe wall).
(v) Ovality (oval or egg-shaped pipe).
(vi) Laminations (internal separation in pipe wall creating layers parallel to the pipe surface).
(vii) Insufficient amount of ultraviolet light stabilizers.
(viii) Pipe diameter and wall thickness variations outside of tolerance.

(3) Fittings (including metallic fittings) used to join plastic pipe. Defects may involve the
(6) Encroachment records.
   (i) Proximity to pipeline as indicated from patrols and surveys.
   (ii) Indications of digging where unreported damage could have occurred.
   (iii) History of excavation damage.
   (iv) Proposed construction drawings.
   (v) Damage to locating wires or facilities.
   (vi) Construction by others of steam or electric facilities close to the plastic pipeline.

(c) Other considerations.
   (1) Preventive and mitigative measures that have been implemented.
   (2) Vehicular damage to aboveground facilities with the potential to cause damage to plastic facilities connected below ground.
   (3) Inadequate cover.
   (4) Activities in the vicinity of the pipeline that do not require one-call notification (e.g., new road construction, blasting, logging, deep tilling, land leveling).
   (5) Excavation by agencies that are exempt from one-call notification.
   (6) Ability to locate (see 12.4(a)(4) above).
   (7) Pipe installed in casing.

12.7 Incorrect operations (includes human error).
(a) All facilities are subject to the threat of incorrect operations. This threat is time-independent and may occur at any time. Potential incorrect operation threats include the following.
   (1) Failure to follow correct operating procedures.
   (2) Following incorrect, outdated, or incomplete operating procedures.
   (3) Unqualified person performing an unfamiliar task.
   (4) Use of uncalibrated or unauthorized tools.

(b) Data collection.
ASME B31.8S Appendix A8 relates to metallic pipelines, but offers a useful format for data that should be collected to evaluate a plastic pipeline for incorrect operations. The following list may be applicable to plastic pipelines and should be considered by the operator.
   (1) Procedure review information.
      The procedure review for completeness and effectiveness should include the following.
      (i) Procedural manual for operations, maintenance, and emergencies.
      (ii) Damage prevention program.
      (iii) Operator qualification program.
      (iv) Anti-drug and alcohol program.
      (v) Safety manual.
      (vi) IMP periodic evaluations.
      (vii) Adherence to operator procedures.
      (viii) Operator procedures for conducting post-incident, abnormal operations, and failure investigations.

   (2) Audit information.
   The results of both internal and external audits should be reviewed. Internal audits might include self audits in the following areas.
      (i) Field operations.
         (A) Valve inspections and maintenance.
         (B) Leak surveys.
         (C) Cathodic protection of in-line metallic component or parts.
         (D) Patrolling.
      (ii) Construction activities.
      (iii) Office operations (e.g., documentation, processes).
      (iv) Mapping.
(3) Failures caused by incorrect operations.
Failures or potential failures caused by an incorrect operation may be found in the following reports.
(i) Abnormal operations.
(ii) Safety-related conditions.
(iii) Root-cause analysis.
(iv) Incidents.
(v) Near misses.
(vi) OQ disqualifications.

12.8 Weather-related and outside forces.
Weather-related and outside force threats have the capability to create extreme loading conditions on plastic pipelines (see guide material under §§192.317 and 192.615).

(a) Potential weather-related and outside forces threats include the following.
(1) Flooding (see 6 of the guide material under §192.613).
(2) Frost heave.
(3) Earthquakes.
(4) Landslides.
(5) Subsidence.
(6) Extreme loads (e.g., equipment crossings).

(b) Data collection.
ASME B31.8S, Appendix A9 generally relates to metallic pipelines, but may be useful as a format for data that should be collected to evaluate a plastic pipeline for weather and outside force damage. The following may be applicable to plastic pipelines and should be considered by the operator.

(1) Pipe joining method.
Pipelines that include the following joint types may be more susceptible to leakage or failure from the threat of weather-related and outside forces than pipelines constructed using modern joining methods.
(i) Mechanical fittings that do not have restraints to prevent pipe pull-out.
(ii) Solvent cement.
(iii) Adhesive.
(iv) Heat fusions with a history of poor or cold fusions.

(2) Topography and soil conditions.
The following topographical areas should be examined to determine if the threat associated with extreme loading conditions exists.
(i) Slopes prone to movement or other unstable areas that would induce additional stresses in a pipeline due to the movement of soil.
(ii) Extremely saturated soils that produce buoyant forces on pipelines.
   (A) River and stream crossings.
   (B) Low lands, floodplains, and swamps.
   (C) Coastal areas prone to tidal surges from hurricanes or tropical storms.
(iii) Areas with deep frost line depths.
(iv) Highly expansive or unstable soils (e.g., some clays).
(v) Locations with known geologic conditions that contribute to instability (e.g., karst topography, sinkholes, underground mining, other subsidence areas).

(3) Fault zones.
The following should be considered in evaluating an earthquake fault zone condition.
(i) Proximity of earthquake fault zones to pipeline location.
(ii) Previous earthquake activity.
(iii) Probability of future earthquake activity along fault.
(iv) Analyses of leaks or other damage attributable to earthquake activity.
<table>
<thead>
<tr>
<th>2 GOVERNMENTAL DOCUMENTS (Continued)</th>
</tr>
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<tbody>
<tr>
<td><strong>OPS ADB-10-03</strong></td>
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<td><strong>OPS ADB-10-08</strong></td>
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<td><strong>OPS ADB-11-02</strong></td>
</tr>
<tr>
<td><strong>OPS ADB-11-05</strong></td>
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<td><strong>OPS ADB-12-02</strong></td>
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<tr>
<td><strong>OPS ADB-12-03</strong></td>
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<td><strong>OPS ADB-2012-07</strong></td>
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<td><strong>OPS ADB-12-08</strong></td>
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<td><strong>OPS ADB-2016-01</strong></td>
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<td><strong>OPS ALN-88-01</strong></td>
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<td><strong>OPS ALN-89-01</strong></td>
</tr>
<tr>
<td><strong>OPS-DOT.RSPA/DMT 10-85-1</strong></td>
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<td><strong>OPS TTO No. 5</strong></td>
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</table>
### 2 GOVERNMENTAL DOCUMENTS (Continued)

<table>
<thead>
<tr>
<th>Source</th>
<th>Description</th>
<th>§192.613</th>
<th>§192.917</th>
<th>§192.929</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPS TTO No. 8</td>
<td>Technical Task Order – Stress Corrosion Cracking Study, Michael Baker, Jr., Inc., January 2005</td>
<td>§192.613</td>
<td>§192.917</td>
<td>§192.929</td>
</tr>
<tr>
<td>PHMSA-OPS</td>
<td>§192.611</td>
<td>§192.620</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PHMSA-OPS</td>
<td>&quot;Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Gas Pipelines&quot;</td>
<td>§192.620</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PHMSA-OPS</td>
<td>Notice – Development of Class Location Change Waiver Criteria (69 FR 38948, June 29, 2004)</td>
<td>§192.611</td>
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</tr>
<tr>
<td>PHMSA-OPS</td>
<td>Training Guide for Operators of Small LP Gas Systems (also referred to as &quot;Guidance Manual&quot;)</td>
<td>§192.1</td>
<td>§192.11</td>
<td></td>
</tr>
</tbody>
</table>
GUIDE MATERIAL APPENDIX G-192-9

TEST CONDITIONS FOR PIPELINES OTHER THAN SERVICE LINES

This table is presented as a guide to the application of the test requirements in §§192.143, 192.503, 192.505, 192.507, 192.509, 192.513, and 192.619 as they apply to pipelines other than service lines.

<table>
<thead>
<tr>
<th>Maximum Operating Pressure</th>
<th>Under 30 Percent SMYS</th>
<th>30 Percent SMYS and Over</th>
<th>Plastic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Test Medium</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water</td>
<td>Water</td>
<td>Water</td>
<td>Water</td>
</tr>
<tr>
<td>Air</td>
<td>Air</td>
<td>Air</td>
<td>Air</td>
</tr>
<tr>
<td>Natural gas</td>
<td>Natural gas</td>
<td>Natural gas</td>
<td>Natural gas</td>
</tr>
<tr>
<td>Inert gas</td>
<td>Inert gas</td>
<td>Inert gas</td>
<td>Inert gas</td>
</tr>
<tr>
<td>Maximum Test Pressure</td>
<td>See Note (3)</td>
<td>See Note (3)</td>
<td>See Note (3)</td>
</tr>
<tr>
<td>Minimum Test Pressure</td>
<td>10 psig</td>
<td>90 psig</td>
<td>Maximum operating pressure multiplied by class location factor in §192.619 (a)(2)(ii); See Note (1)</td>
</tr>
<tr>
<td>Minimum Test Duration</td>
<td>See Note (5)</td>
<td>1 Hour and see Note (5)</td>
<td>8 Hours and see Notes (5) &amp; (6)</td>
</tr>
</tbody>
</table>

Notes:
1. Whenever test pressure is 20% SMYS or greater and natural gas, inert gas or air is the test medium, the line must be checked for leaks either by a leak test at a pressure greater than 100 psig but less than 20% SMYS or by walking the line while the pressure is held at 20% SMYS (§192.507(b)).
2. See temperature limitations for thermoplastic material in §192.513(d).
3. Refer to §192.503(c) for limitations when testing with air, natural gas, or inert gas. There are no limitations for water test. For all test media, pipeline components must be taken into consideration when determining the maximum test pressure. When water is used as the test medium, it is essential to consider elevation differences to avoid overpressuring pipe at lower elevations in the segment. The pressure at lower elevations is determined by adding 0.43 psig for every foot of elevation differential to the test pressure, measured at a higher point.
4. Refer to §192.505(a) for testing criteria covering pipelines located within 300 feet of buildings and §192.505(b) covering compressor stations.
5. Duration determined by volumetric content of test section, test medium, test pressure, thermal effects, leak criteria, and instrumentation in order to ensure discovery of all potentially hazardous leaks. See 2 of the guide material under §192.509 and 4 of the guide material under §192.513.
(6) Refer to §192.505(e) for fabricated units and short sections of pipe.
### TEST CONDITIONS FOR SERVICE LINES

#### 1 SUMMARY OF PRESSURE TEST REQUIREMENTS

This table is presented as a guide to the application of the test requirements of §192.511 and §§192.503, 192.507, 192.509, 192.513, and 192.619 as applied to service lines.

<table>
<thead>
<tr>
<th>Maximum Operating Pressure</th>
<th>Other Than Plastic</th>
<th>Plastic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Test Medium</td>
<td>Less than 1 psig</td>
<td>Water Air Natural Gas Inert Gas</td>
</tr>
<tr>
<td></td>
<td>1 psig to 40 psig</td>
<td>Water Air Natural Gas Inert Gas</td>
</tr>
<tr>
<td></td>
<td>Over 40 psig but less than 100 psig</td>
<td>Water Air Natural Gas Inert Gas</td>
</tr>
<tr>
<td></td>
<td>100 psig and over</td>
<td>Water Air Natural Gas Inert Gas</td>
</tr>
<tr>
<td></td>
<td>0 to 200 psig</td>
<td>See Note (1)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Maximum Test Pressure</th>
<th>Other Than Plastic</th>
<th>Plastic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Test Medium</td>
<td>See Note (3)</td>
<td>See Note (3)</td>
</tr>
<tr>
<td></td>
<td>See Note (3)</td>
<td>See Note (3)</td>
</tr>
<tr>
<td></td>
<td>See Note (3)</td>
<td>See Note (3)</td>
</tr>
<tr>
<td></td>
<td>See Note (3)</td>
<td>See Note (3)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Minimum Test Pressure</th>
<th>Other Than Plastic</th>
<th>Plastic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Test Medium</td>
<td>See Note (5)</td>
<td>3 x design pressure except for PA-11</td>
</tr>
<tr>
<td></td>
<td>50 psig</td>
<td>2.5 x design pressure for PA-11; See Note (4)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Minimum Test Duration</th>
<th>Other Than Plastic</th>
<th>Plastic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Test Medium</td>
<td>See Note (8)</td>
<td>See Notes (6) &amp; (8)</td>
</tr>
<tr>
<td></td>
<td>See Note (8)</td>
<td>See Notes (6) &amp; (8)</td>
</tr>
<tr>
<td></td>
<td>See Notes (6) &amp; (8)</td>
<td>See Notes (8) &amp; (9)</td>
</tr>
</tbody>
</table>

**Notes:**

1. Refer to §192.123 for design pressure limitations for plastic pipe including PA-11.
2. See temperature limitations for thermoplastic material in §192.513(d).
3. Refer to §192.503(c) for limitation when testing with air, natural gas, or inert gas. Limited also to the design pressure of service line component (§192.619).
5. Recommended practice is a minimum of 10 psig.
6. Whenever test pressure stresses pipe to 20% SMYS or more, see §§192.507 and 192.511(c) for additional requirements.
7. See §192.619 for Class 1 and Class 2 locations.
8. Time duration to be sufficient to ensure discovery of all potentially hazardous leaks. Recommended practice is a minimum of 5 minutes. See 2 of the guide material under §192.509.
9. See 4 of the guide material under §192.513.
2 TESTING SERVICE LINES EQUIPPED WITH EXCESS FLOW VALVES

2.1 Pressurizing the service line.
When pressurizing a service line equipped with an excess flow valve (EFV) during either testing or service activation, the operator should introduce either the test medium or gas at a flow rate that does not activate the EFV. EFV activation may be indicated by a sudden increase in pressure as noted on a pressure gauge at the injection point or the lack of a rapid buildup of pressure at the service line riser. If activated, bypass-type EFVs (EFVB) should reset automatically; non-bypass types (EFVNB) should be reset following their manufacturers’ instructions.

2.2 Testing the EFV.
Prior to service line testing or service activation, the operator may opt to test the EFV for shutoff by first introducing the test medium at a high flow rate. If the EFV does not operate as designed, it should be replaced.
**GUIDE MATERIAL APPENDIX G-192-20**

(See guide material under §192.281)

**FUSION EQUIPMENT MAINTENANCE / REPAIR INSPECTION FORM**

Inspector: ____________________________ Date: ________________

Equipment Description: _______________________________________

<table>
<thead>
<tr>
<th>Inspection Items</th>
<th>OK or Not Applicable (N/A)</th>
<th>Needs Repairs</th>
<th>Date Repaired</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>UNIT</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Machine is clean</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. All pins and snap rings in place</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. All nuts and bolts tight</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4. All placards and handles in place</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5. All clamp knobs free and lubricated</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6. Cords and plugs in good condition</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7. All necessary hardware on machine</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8. Side play in bushings within tolerance</td>
<td></td>
<td></td>
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<tr>
<td>9. Guide rods not damaged</td>
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<td>10. Clamping jaw and insert grooves clean</td>
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<td>11. Hydraulic gauge reads correctly</td>
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(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
- OSHA letter to AGA dated May 25, 1994 re: Confined Space
- OSHA letter to AGA dated October 30, 1992 re: Process Safety Management
- OSHA letter to AGA dated July 19, 1990 re: Excavation Standards
U.S. Department of Labor

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. Sablock of Sempra Energy, as to whether OSHA is precluded 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 “taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and a rescue harness and line.” 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.
In a telephone conference on January 13, between OSHA and Solicitor of Labor staff and Office of Pipeline Safety representatives, OPS indicated that the regulations indeed constitute the agency’s intent to regulate the use of respirators in operations, maintenance, and emergencies. OSHA’s respirator standard addresses the same working conditions as the OPS regulations listed above. The OSHA standard requires employers whose workplaces contain actual or potential hazardous concentrations of air contaminants to establish a respiratory protection program, which must include the provision of appropriate respirators for the hazard involved and procedures for the proper use of those respirators. The OPS regulations require the provision and use of emergency equipment, including respirators, to protect against unsafe accumulations of vapors and gases in pipeline trenches. The OPS regulations thus require protection against the same hazard – unsafe concentrations of air contaminants – addressed by the OSHA standard. OSHA concludes that it is therefore preempted, under §4(b)(1), from enforcing the Respiratory Protection Standard against employers subject to the OPS regulations, namely, pipeline owners and operators. However, OSHA is not preempted from enforcing the standard as to contractors, or other entities not covered by the requirements of 49 CFR Part 192. Texas Eastern Transmission Corp. and Sinapp Company - Staten Island, Inc., 3 BNA OSHC 1601, 1605 (Nos. 4091 and 4078, 1975). OSHA has conferred with representatives of OPS responsible for enforcing the OPS regulations, and they have informed OSHA that they concur in these conclusions.

Please feel free to distribute this letter to any of your members with an interest in this subject. We will make our field offices aware of this interpretation through distribution of this letter, as well. With respect to your members in any of the 23 States with federally-approved state OSHA plans, we should note that State Plans operate under authority of State rather than Federal law, and the restrictions in section 4(b)(1) do not necessarily apply. OSHA will furnish an information copy of this letter to each State plan State and encourage them to consider a similar policy interpretation, but since coverage provisions may differ somewhat under the laws in individual States, your members in State plan States may wish to contact the State plan agency directly.

Sincerely,

Richard E. Fairfax
Director
Directorate of Compliance Programs

cc:
Mr. Gordon Murdock, Questar
Mr. Stephen M. Sableck, Sempra Energy
Mr. Greg F. Janson, Southwest Gas Corporation
Mr. Terry Boss, Interstate Natural Gas Association of America
David J. Muchow, Esq.
General Counsel and
Corporate Secretary
American Gas Association
1515 Wilson Boulevard
Arlington, VA 22209

Dear Mr. Muchow:

This letter is in response to the American Gas Association's (A.G.A) Request For Clarification, Or In The Alternative, Petition For Administrative Stay, dated March 5, 1993. A.G.A. has requested that OSHA clarify that, in light of the preemption provision in Section 4(b)(1) of the Occupational Safety and Health Act, the final rule on Permit-Required Confined Spaces (PRCS), which requires employers to implement safety precautions prior to and during entry into confined spaces whenever serious atmospheric, mechanical or other types of hazards are present, does not apply to gas utility vaults. The Department of Transportation's Office of Pipeline Safety (OPS) has issued regulations covering natural gas distribution and transmission facilities, including vaults and related spaces. 49 C.F.R. §§191, §192 (1991).

At a meeting on April 8, 1993 between OSHA and Solicitor of Labor staff and A.G.A. representatives concerning the March 5 submission, A.G.A. engineers stated that the presence of gas was the only hazard ordinarily encountered by employees in conducting inspections and performing normal maintenance work in vaults. A.G.A. expressed concern that broad application of the PRCS standard to vaults would require significant changes in its members' operating procedures, which conform to OPS procedures for minimizing the hazards of gas in such spaces. According to A.G.A., this would subject gas utility companies to conflicting federal requirements and could lead to disruption of services.

As A.G.A. has pointed out, section 4(b)(1) of the OSH Act, 29 U.S.C. §653(b)(1) (1988), precludes OSHA from applying its standards to working conditions that are regulated by other federal agencies. The phrase "working conditions" encompasses both a worker's surroundings and the hazards incident to his work. See, Columbia Gas of Pennsylvania v. Marshall, 636 F.2d 913 (3d Cir. 1980); Southern Railway Co. v. OSHRC, 539 F.2d 335 (4th Cir. 1976); Southern Pac. Transp. Co. v. U.Sery, 539 F.2d 386, 390 (5th Cir. 1976). See also In re Inspection of Norfolk Dredging Co., 783 F.2d 1526, 1530-32 (11th Cir. 1986). Thus, an OSHA...
standard does not apply to the extent that another federal agency prescribes or enforces standards addressing the same general working conditions.

Current OPS regulations contain requirements for adequately ventilating large vaults and for providing a means for testing the atmospheres of sealed vaults prior to entry, 49 C.F.R. §192.187 (1991); for designing and locating vaults to minimize the entrance of water, 49 C.F.R. §§192.85, 189 (1991); for periodically inspecting vault equipment and for repairing leaking or faulty equipment, 49 C.F.R. §192.749 (1991), and for minimizing the danger of fire, or explosion in any structure or area in which gas might be present, 49 C.F.R. §192.751 (1991). Operators must also report to OPS any incident involving a death or serious injury associated with the release of gas from a pipeline, 49 C.F.R. §191.5 (1991). While these provisions are primarily directed to the hazards of fire and explosion, they appear sufficiently related to the general problem of hazardous vault atmospheres to preempt all OSHA regulation of such hazards under the PRCS, including fire, explosions, toxicity and oxygen deficiency. *Southern Pac.* 539 F.2d at 391 (noting that comprehensive Federal Railroad Administration treatment of the general problem of railroad fire protection would displace all OSHA regulation on fire protection even if the FRA regulations differed from OSHA's).

Furthermore, OSHA recognizes that the application of the PRCS standard to atmospheric hazards in vaults, even if limited to hazards such as toxicity or oxygen deficiency, could impair a pipeline operator's ability to respond quickly to protect the public safety in a gas emergency, a result in apparent conflict with OPS's overall scheme. See 49 C.F.R. §192.615, §192.711 (1991). *Cf. Southern Pac.* 539 F.2d at 392 (dominant agency regulations may displace OSHA regulations by articulating a formal position that a given working condition should go unregulated or that certain regulations - and no others - should apply to a defined subject). For these reasons, OSHA does not intend to enforce the PRCS standard in vaults to the extent that such enforcement would be based on hazards that relate to gas or other hazards that are addressed by DOT/OPS regulations.

However, enforcement of the PRCS standard in vaults is not entirely preempted. Because the OPS regulatory scheme primarily relates to the hazards of gas in vaults, the more comprehensive PRCS standard may apply to these spaces to the extent that hazards other than those related to gas are involved. *Norfolk Dredging Co.* 783 F.2d at 1531; *Southern Pac.* 539 F.2d at 391. As an example, if a vault contains no gas but employees encounter other, unusual hazards which could impair the entrant's ability to escape from the space, some of the procedures in the PRCS standard may apply. Based on A.G.A.'s representation that such other hazards are not reasonably predictable in its vaults,
A.G.A.'s members need not develop a permit-required confined space program to address such hazards in advance. If such unusual hazards are encountered, they should be dealt with by following sound industrial hygiene and safety procedures, including the procedures set forth in §1910.145(d) that are relevant in light of the particular hazards involved. The discovery of such hazards initially by workers, where the employer could not reasonably have known of the existence of the hazard, will not constitute a violation of the OSH Act or the PRCS standard.

This interpretation addresses the concerns raised in A.G.A.'s March 5, 1993 submission and discussed during the meeting of April 8, 1993 and is consistent with the agency's prior enforcement policy. Based upon the information A.G.A. has provided, OSHA expects that the PRCS standard would apply only in unusual circumstances in which hazards not normally encountered in day-to-day operations are present.

The policy stated in this letter applies to employers and vaults regulated by current OPS regulations. Should relevant OPS regulations be repealed or modified, it would be necessary for OSHA to reconsider its position. However, as long as current OPS regulations remain in effect, OSHA will not apply the PRCS standard to working conditions addressed by DOT/OPS regulations in vaults.

Sincerely,

Joseph A. Dear
Assistant Secretary
Mr. Michael Baly, III  
President  
American Gas Association  
1515 Wilson Boulevard  
Arlington, Virginia 22209  

Dear Mr. Baly:

This is in response to your letter of August 18, requesting a decision from the Occupational Safety and Health Administration (OSHA) on whether our final rule on Process Safety Management (PSM) applies to natural gas distribution and transmission facilities.

It has long been OSHA’s position that the agency cannot issue a Section 4(b)(1) exemption for an entire industry. Additionally, both the Occupational Safety and Health Review Commission (OSHRC) and the courts have rejected the industrywide exemption concept. However, this does not mean that certain specific work operations may not be determined to be outside OSHA jurisdiction, given the proper circumstances.

On October 1, OSHA staff met with their counterparts from the Department of Transportation’s Office of Pipeline Safety (OPS) to discuss OPS regulations vis-a-vis PSM. OPS staff gave generously of both their time and expertise. They outlined their current regulations, as well as proposals which are in various stages of the rulemaking process.

As a result of that meeting, and following our review of OPS regulations, OSHA has concluded that current OPS regulations address the hazards of fire and explosion in the gas distribution and transmission process. Accordingly, OSHA has determined that the agency is precluded from enforcing the PSM rule over the working conditions associated with those hazards.

Today’s interpretation addresses only the applicability of the PSM standard to the gas transmission or distribution process as noted above; it does not address the applicability of OSHA standards other than PSM, or the applicability of OSHA requirements to operations other than those described above. For example, natural gas processing facilities, in our view, would be subject to OSHA coverage notwithstanding today’s interpretation. Finally, it should be noted that employers not subject to particular OPS requirements remain fully subject to OSHA requirements including the PSM standard.
Should current OPS requirements regarding hazards in gas transmission or distribution operations be repealed or modified by Congress or by OPS, it would be necessary for OSHA to revisit this issue. However, as long as current OPS rules and requirements remain in effect, OSHA will not seek to enforce the PSM standard against employers who are subject to OPS requirements with respect to fire or explosion hazards in connection with gas transmission or distribution.

Thank you for bringing the concerns of your membership to our attention. If we can be of any further assistance, please do not hesitate to contact us.

Sincerely,

Dorothy L. Strunk
Acting Assistant Secretary
Mr. David L. Muchow  
General Counsel and Corporate Secretary  
American Gas Association  
1515 Wilson Boulevard  
Arlington, Virginia 22209  

Re: Preemption of Certain OSHA Excavation Standards by DOT Office of Pipeline Safety Standards  

Dear Mr. Muchow:  

The Occupational Safety and Health Administration's (OSHA) excavation standard issued on October 31, 1989, generally applies to all employers who engage in excavation work or who have employees exposed to hazards arising out of such work. During the rulemaking proceeding leading to the standard's issuance, the American Gas Association (AGA) contended that certain requirements should not apply to employers engaged in natural gas transmission and distribution. The AGA pointed out that such employers must comply with safety standards issued by the Department of Transportation's (DOT) Office of Pipeline Safety (OPS), and that certain OPS standards addressed the same working conditions as did specific subsections of OSHA's proposed standard. The AGA's comments particularly addressed the following two subsections of the OSHA standard:  

**29 CFR § 1926.651(g)(1)(iii):**  

Adequate precaution shall be taken such as providing ventilation, to prevent employee exposure to an atmosphere containing a concentration of a flammable gas in excess of 20 percent of the lower flammable limit of the gas.  

**29 CFR § 1926.651(g)(2)(i):**  

Emergency rescue equipment, such as breathing apparatus, a safety harness and line, or a basket stretcher, shall be readily available where hazardous atmospheric conditions exist or may reasonably be expected to develop during work in an excavation. This equipment shall be attended when in use.
In response to the gas industry's continuing concern over these two subsections, we have carefully considered whether existing OOS standards preempt OSHA from enforcing them against employers who are subject to the OOS standards. For the following reasons, we have determined that such OSHA enforcement is preempted.

OSHA is the agency primarily responsible for assuring safe and healthful working conditions in American workplaces. However, Congress has delegated to other Federal agencies the responsibility for regulating particular workplace health and safety matters. Where other agencies have such authority, their regulations have priority over OSHA's, and OSHA standards do not apply to working conditions that the other Federal agencies have regulated. This conclusion follows from section 4(b)(1) of the Occupational Safety and Health Act (OSH Act), which provides that the OSH Act does not apply to working conditions with respect to which other Federal agencies "exercise statutory authority to prescribe or enforce standards or regulations affecting occupational safety or health."

The Natural Gas Pipeline Safety Act gives DOT the responsibility for issuing safety standards governing the transportation of natural gas through pipelines. OOS regulations issued under this mandate are found at 49 CFR Parts 191, 192, and 193. Certain of these OOS regulations address the maintenance and repair of gas pipelines, work that often requires employees to work in excavations opened for the purpose of gaining access to the lines. To the extent that the OOS regulations address the same occupational safety and health conditions addressed by the OSHA excavation standard, section 4(b)(1) precludes OSHA's enforcement of its standard.

Subsection 1926.651(g)(1)(iii) of the OSHA excavation standard requires that the concentration of flammable gas be maintained below 20 percent of the lower explosive limit. This provision is intended to prevent fires and explosions that could result from explosive concentrations of flammable gases. The OOS regulation at 49 CFR § 192.751 addresses the same safety problem, requiring pipeline operators to "minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion." This OOS regulation therefore preempts enforcement of subsection 1926.651(g)(1)(iii) against employers who are subject to the DOT standard.

Subsection 1926.651(g)(2)(i) of the OSHA standard requires that emergency rescue equipment be provided where hazardous atmospheric conditions exist or may reasonably be expected to develop in an excavation. As the AGA has pointed out, OOS has adopted a standard requiring that precautions be taken against anticipated emergencies that can arise when a gas pipeline is being repaired. The OOS standard at 49 CFR § 192.615 requires gas pipeline operators to anticipate emergencies and develop
plans to meet them. Since both the OSHA and OPS standards require pipeline operators to anticipate potential emergencies and implement precautions before such emergencies occur, OSHA concludes that the OPS standard addresses the same working condition as subsection 1926.651(g)(2)(i) and therefore preempts enforcement of that subsection against employers subject to the OPS standard.

In concluding that these two OSHA subsections cannot be enforced against employers subject to the DOT pipeline safety standards, OSHA has not attempted to determine whether the OPS standards offer appropriate protection against the hazards involved. It is sufficient that they address the same conditions addressed by the OSHA subsections. Should DOT repeal or amend the standards discussed earlier, it would be necessary for OSHA to reevaluate this issue. However, as long as the present DOT standards at 49 CFR §§ 192.751 and 192.615 remain in effect, OSHA will not attempt to enforce 29 CFR §§ 1926.651(g)(1)(iii) and 651(g)(2)(i) against employers who are subject to the OPS standards.

Finally, this letter does not affect potential OSHA enforcement of other provisions of the excavation standard. Nor does this letter affect the right of individual gas companies to contest jurisdiction on grounds of preemption of other provisions of the excavation standard.

Sincerely,

Gerard F. Scannell
Assistant Secretary
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Note: GMA means Guide Material Appendix; otherwise, Appendix means Appendix to Part 192.

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