GAS PIPING technology committee

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October 9, 2009

Dear *Guide* Purchaser,

Enclosed is Addendum 1 to ANSI GPTC Z380, *Guide for Gas Transmission and Distribution Piping Systems*, 2009 Edition. Addenda are formatted to enable the replacement of pages in your *Guide* with the updated enclosed pages. Please follow the table on page 2.

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

Sincerely

Paul Cabot

Secretary
GPTC/Z380

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GPTC GUIDE FOR GAS TRANSMISSION AND DISTRIBUTION PIPING SYSTEMS

2009 EDITON

ADDENDUM 1, May 2009

The primary changes in this addendum are marked by wide vertical lines inserted to the left of modified text, overwriting the left border of most tables, and use of a block symbol (**▌**) where needed. The Federal Regulations were changed by one amendment action that affected one section of the Guide, being §192.7. Seven GPTC transactions affected 13 sections of the Guide.

Editorial updates include application of the Editorial Guidelines, updating reference titles, adjustments to page numbering, and adjustment of text on pages. Editorial updates affected 12 sections of the guide.

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

Amdt. or Docket Number: FS Amendment
TR Number: New or Updated GM
GMUR: GM Under Review
EU: Editorial Update
ER: Editorial Refinement

Guide Section	Reason For Change	Pages to be Removed	Replacement Pages
Title Page	EU	i/ii	i/ii
Table of Contents	EU	vii/viii thru xi/xii	vii/viii thru xi/xii
Historical Reconstruction of Part 192	RIN 2137-AE42	xxv/xxvi	xxv/xxvi
Historical Record of Amendments to Part 192	RIN 2137-AE42	lv/lvi thru lxv/lxvi	lv/lvi thru lxv/lxvi
Membership List	EU		
Subpart A 192.3	TR03-19, TR03-45, TR04-61	17/18, 21/22 thru 27/28	17/18, 21/22 thru 27/28
192.7	RIN 2137-AE42		
Subpart C 192.121	EU	59/60	59/60
Subpart F 192.279	TR08-07	119/120, 121/122	119/120, 121/122
192.281	TR07-01		
192.283	TR07-01	125/126	125/126
Subpart G 192.319	TR00-11	137/138	137/138
Subpart H 192.361	TR00-11	155/156	155/156
192.367	EU	159/160	159/160
Subpart I 192.489	EU	195/196	195/196
Subpart K 192.557	EU, TR06-14	213/214, 215/216	213/214, 215/216
Subpart L 192.612	TR04-61	229/230 thru 237/238	229/229(a) thru 237/238
192.613	TR03-45		
192.614	TR06-14, TR07-01		
Subpart M 192.749	EU	297/298	297/298
192.755	TR06-14	303/304	303/304
GMA G-192-1	EU, TR00-11, TR03-45, TR06-14, TR08-07	417/418 thru 437/438	417/418 thru 437/438
GMA-G-192-3	EU	447/448	447/448
GMA G-192-8	EU	477/478	477/478
GMA G-192-15A	TR00-11	561/562, 563/564	561/562, 563/564
GMA G-192-15B (New)	TR00-11	(None)	564(a)/564(b), 564(c)/564(d)
GMA-G-192-17	EU	569/570 thru 573/574	569/570 thru 573/574
GMA G-192-18	TR06-14	575/576	575/576

Guide for Gas Transmission and Distribution Piping Systems

2009 Edition

Addendum 1, May 2009

an American National Standard

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

Secretariat:
American Gas Association

Approved by
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ANSI/GPTC Z380.1-2009, Addendum No.1-2009
Catalog Number: Z38010901

PLEASE NOTE

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

CAUTION

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

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

Conversions of figures to electronic format courtesy of ViaData Incorporated.

GUIDE MATERIAL APPENDICES

Reserved

HISTORICAL RECONSTRUCTION OF PART 192

(Complete through Amendment RIN 2137-AE42)

Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART A – GENERAL	192.1		192-27, 192-67, 192-78, 192-81, 192-92, RIN 2137-AD77, 192-102, 192-103
	192.3		192-13, 192-27, 192-58, 192-67, 192-72 + Ext., 192-78, 192-81, 192-85, 192-89, RIN 2137-AD43, 192-93, 192-94, 192-98, RIN 2137-AD77
	192.5		192-27, 192-56, 192-78, 192-85
	192.7		192-37, 192-51, 192-68, 192-78, 192-94, RIN 2137-AD77, 192-99, 192-102, 192-103, RIN 2137-AE29, RIN 2137-AE25, RIN 2137-AE29 (#2), RIN 2137-AE42
	192.8	04/14/06	192-102
	192.9		192-72 + Ext., 192-95 Corr., 192-102
	192.10	03/19/98	192-81, RIN 2137-AD77
	192.11	11/13/72	192-68, 192-75, 192-78
	[192.12]		192-10, 192-36 (removed)
	192.13		192-27, 192-30, 192-102
	192.14	12/30/77	192-30
	192.15		
	192.16	09/13/95	192-74, 192-74A, 192-84
	[192.17]	01/01/71	192-1, 192-27A Ext., 192-38 (removed)
SUBPART B – MATERIALS	192.51		
	192.53		
	192.55		192-3, 192-12, 192-51, 192-68, 192-85
	192.57		192-62 (removed and reserved)
	192.59		192-19, 192-58
	192.61		192-62 (removed and reserved)
	192.63		192-3, 192-31, 192-31A, 192-61, 192-61A, 192-62, 192-68, 192-76
	192.65		192-12, 192-17, 192-68

HISTORICAL RECONSTRUCTION OF PART 192

(Continued)

Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART C – PIPE DESIGN	192.101		
	192.103		
	192.105		192-47, 192-85
	192.107		192-78, 192-84, 192-85
	192.109		192-85
	192.111		192-27
	192.112	12/22/08	RIN 2137-AE25
	192.113		192-37, 192-51, 192-62, 192-68, 192-85, 192-94
	192.115		192-85
	192.117		192-37, 192-62 (removed and reserved)
	192.119		192-62 (removed and reserved)
	192.121		192-31, 192-78, 192-85, 192-94, 192-103, RIN 2137-AE26
	192.123		192-31, 192-78, 192-85, 192-93, 192-94, 192-103, RIN 2137-AE26
	192.125		192-62, 192-85

HISTORICAL RECORD OF AMENDMENTS TO PART 192

(Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
[No Amdt No.]	Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines	73 FR 72737	12/01/08	RIN 2137-AE25 [Ref. as "Eff. date stayed"]	12/22/08	112, 328, 611, 619, 620
[No Amdt No.]	Polyamide-11 (PA-11) Plastic Pipe Design Pressures	73 FR 79002	12/24/08	RIN 2137-AE26	01/23/09	121, 123
[No Amdt No.]	Administrative Procedures, Address Updates, and Technical Amendments [Adopts interim final rule with modifications.]	74 FR 2889	01/16/09	RIN 2137-AE29 [Ref. as (#2)]	02/17/09	7, 727, 949, 951
[No Amdt No.]	Incorporated by Reference Update: American Petroleum Institute (API) Standards 5L and 1104*	74 FR 17099	04/14/09	RIN 2137-AE42	04/14/09	7

* Issued as a Direct Final Rule (DFR) or Interim Final Rule.

Reserved

GAS PIPING TECHNOLOGY COMMITTEE MEMBERSHIP LIST

Abbreviations:
Chairperson: Chair
First Vice Chairperson: 1st V Chair
Second Vice Chairperson: 2nd V Chair
Secretary: Sec
Damage Prevention - Emergency Response: DP/ER
Operation and Maintenance: O&M

		DIVISIONS			TASK GROUPS					SECTIONS			
	Main Body	**Distribution**	**Manufacturers**	**Transmission**	**Design**	**DP/ER**	**IMP/Corrosion**	**O&M/OQ**	**Plastic Pipe**	**Editorial**	**Executive**	**Liaison**	**Regulations**
Abraham, Richard A. Marathon Pipe Line LLC, Findlay, OH	X	X				X				X			
Affonso, Joaquin J. Consumers Energy, Jackson, MI	X			X		X	X						X
Alexander, Thomas D. Willbros Engineers, Inc., Tulsa, OK				X	X								
Amick, Patrick M. Marathon Oil Co., Houston, TX				X				X					
Armstrong, Glen F. EN Engineering, Woodridge, IL	X	Chair				X	X		X		X		
Ashcraft, Nicholas D. Mears Group, Columbus, OH		X					X						
Barkei, David E. We Energies, Milwaukee, WI		X			X		X						
Bateman, Stephen C. City of Long Beach – Gas & Oil Dept., Long Beach, CA		X											
Beaver, Brett Advantica, Mechanicsburg, PA		X			X		X						
Becken, Robert C. Energy Experts International, Pleasant Hill, CA	X			X	X			X					

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Benedict, Andrew G. Opvantek, Inc., Newtown, PA		X						X					
Bennett, Frank M. PPL Interstate Energy Company, Pottstown, PA		X				X	Sec						
Bevers, Bruce S. Williams Gas Pipeline, Houston, TX				X		X		X					
Blaney, Steven D. NY State Dept. of Public Service, Albany, NY	X	X				X	X			X			
Booth, Lloyd E. Telemark Solutions, Coppell, TX			X		X			X					
Boros, Stephen Plastics Pipe Institute, Irving, TX			X						X				
Breaux, David A. BROEN, Inc., Birmingham, AL			X		X			X					
Brown, Charles E. NTH Consultants, Ltd., Lansing, MI		X				X		X					
Bryce, Wayne CINA Corporation, Mahwah, NJ		X					X		X				
Bull, David E. ViaData LP, Tobyhanna, PA	X	X				Sec		X					X
Butler, John Equitable Resources, Charleston, WV					X		X						

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Cabot, Paul W. American Gas Association, Washington, DC	Sec										Sec		
Cadorin, Robert J. TransCanada Corp., Troy, MI	X			Sec				X					
Cardin, Jeanne L. Southwest Gas Corp., Las Vegas, NV				X			X						
Carpenter, Robert Southern California Gas Co., San Diego, CA		X				X	X						
Chin, John S. TransCanada Corp., Troy, MI	X			X	X	X	Chair				X		
Clarke, Allan M. Spectra Energy Corp., Houston, TX				X	X	X	X						
Cody, Leo T. National Grid, Waltham, MA		X				X		X					
Craig, Jim M. McElroy Manufacturing, Inc., Tulsa, OK			X					X	X				
Del Buono, Amerigo J. Steel Forgings, Inc., League City, TX	X		X										
DeVore, James C. Consultant, Green Valley, AZ			X		X		X		X				

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Dolezal, Denise L. Metropolitan Utilities District, Omaha, NE		X			X		X						
Duncombe, Lauri Williams Gas Pipeline, Salt Lake City, UT				X	X		X						
Erickson, John P. American Public Gas Association, Washington, DC		X						X					
Faulkenberry, Michael J. Avista Corp., Spokane, WA		X			X			X					
Fleet, F. Roy F. Roy Fleet, Inc., Westmont, IL	X			X		X				X			
Frantz, John H. Consultant, Philadelphia, PA	X	X						X	X		X	Chair	
Frederick, Victor M., III Omega Tools, Allentown, PA			X					X	X				
Friend, Mary S. Columbia Gas Trmn. Corp., Charleston, WV	X			X		X		X					
Fuller, William R., Jr. Xcel Energy Inc., Denver, CO		X			X		X		X				
Galante, Julie CYCLA Corp., Oakton, VA		X					X						

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Gilchrist, Hart Intermountain Gas Co., Boise, ID		X						X					
Goble, Gregory H. R. W. Lyall & Co., Corona, CA	X		X		X				X				
Groeber, Steven A. Philadelphia Gas Works, Philadelphia, PA		X				X		X	X	X			
Gunther, Karl M. NTSB, Washington, DC	X	X							X				
Hansen, James P. Elster Perfection Corp., Madison, OH			X				X						
Hart, Thomas L. NSTAR Electric & Gas Corp., Westwood, MA		X				X		X					
Hazelden, Glyn Hazelden Group, Oak Park, IL		X				X		X					
Heintz, James R. UGI Utilities, Inc., Reading, PA	1^{ST} V Chair										Chair		
Henry, Jill A. Ohio PUC, Columbus, OH	X	X				X			X				
Hotinger, James M. VA State Corp. Comm., Richmond, VA		X				X	X						

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Humes, Dennis W. Mueller Co.- Gas Products Div., Decatur, IL	X		X										
Hurbanek, Stephen F. NC Utilities Commission, New Bern, NC		X				X							
Huriaux, Richard D. Consulting Engineer, Baltimore, MD	X			X			X						
Kottwitz, John D. MO Public Service Comm., Jefferson City, MO	X	X				Chair		X		X	X		
Koym, Brent L. CenterPoint Energy, Pearl, MS		X			X		X						
Krummert, Lawrence M. Columbia Gas of PA, Inc., New Castle, PA		X						X					
Lewis, Raymond D. Rosen USA, Houston, TX				X			X						X
Loker, Jon O. Pipeline Safety Consultant, Saint Albans, WV	X			X						Chair	X		
Lomax, George S. Heath Consultants Inc., Houston, TX	X		X			X		X					
Lopez, Paul A. El Paso Corp., Colorado Springs, CO				X				X					

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Lueders, John D. DTE Energy - MichCon, Grand Rapids, MI		X				X		X					
Mackay-Smith, Seth UMAC Inc., Malvern, PA	X		X		X	X							
Marek, Marti Southwest Gas Corp., Las Vegas, NV	Chair										X		
McKenzie, James E. Atmos Energy Corp., Jackson, MS		X			X		X						
Miller, D. Lane PHMSA-OPS, Oklahoma City, OK	X	X					X		X	Sec			
Modha, Kirit S. Iroquois Gas Transmission System, Shelton, CT				X			X						
Myers, Clyde A. DOT-PHMSA, Washington, DC				X			X						
Naper, Robert C. Energy Experts International, Waltham, MA	X	X				X							
Nichols, Danny Energy Transfer Company, Houston, TX				X		X	X						
Oleksa, Paul E. Oleksa & Assoc., Akron, OH	X	X			X		X			X			X

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Palermo, Eugene F. Palermo Plastics Pipe Consulting, Friendsville, TN	X		X		X				X				
Peters, Kenneth C. El Paso Corporation, Birmingham, AL	X			Chair		X		Sec			X		
Peterson, Barry A. Performance Pipe, Concord, CA			X						X				
Pioli, Christopher A. Jacobs Consultancy, Pasadena, CA		X			X	X	X						
Quezada, Leticia Nicor Gas, Naperville, IL	X	X				X			X		X		Chair
Reynolds, Donald Lee NiSource Corporate Services, Columbus, OH	X	X			Chair		X				X		
Schmidt, Robert A. Hackney Ladish Inc., Russellville, AR	X		Chair		X						X		
Schow, Boyd L. Williams Gas Pipeline, Salt Lake City, UT				X			X						
Schrunk, Rex Wilbros Engineers, Inc., Kansas City, MO				X			X						
Scott, Edward W. Ameren Services Company, St. Louis, MO		X					X		X				

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Seamands, Patrick A. Laclede Gas Co., Saint Louis, MO		X				X			X	X			
Sher, Philip CT Dept. Public Utility Control, New Britain, CT	2nd V Chair										X		
Siedlecki, Walter V. AEGIS Insurance Services, Inc., East Rutherford, NJ	X	X						X					
Slagle, Richard L. Vectren Energy Delivery, Evansville, IN	X	Sec				X			Chair		X		
Smallwood, Larry Southern Cross Corp., Norcross, GA		X						X					
Themig, Jerome S. Ameren Illinois Utilities, Pawnee, IL		X				X		X					
Torbin, Robert N. Cutting Edge Solutions LLC, Framingham, MA		X					X						
Troch, Steven J. Baltimore Gas & Electric Co., Baltimore, MD		X					X					X	X
Ulanday, Alfredo S. Michigan Gas Utilities, Chicago, IL		X				X		X					
Veerapaneni, Ram DTE Energy – MichCon, Detroit, MI	X			X		X	X			X			X

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Volgstadt, Frank R. Volgstadt & Associates, Madison, OH	X		Sec						Sec				
Weber, David E. Consultant Engineer, Barnstable, MA	X	X							X	X			X
Wells, William M. New Jersey Natural Gas, Wall, NJ		X				X		X					
White, Gary R. PI Confluence, Inc., Houston, TX		X					X						
Wilkes, Alfred L. Performance Pipe, Plano, TX			X		X				X				
Yehle, Steve Excel Energy, St. Paul, MN		X							X				

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 which 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 which is formed and then, expanded in the pipe mill while cold, so that the circumference is permanently increased by at least 0.50 percent.

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: 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.

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: ASTM A381, API Spec 5L. See also *Pipe manufacturing processes*.

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: 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: 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: 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 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: ASTM A53, ASTM A135, and API Spec 5L. See also *Pipe manufacturing processes*.

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

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

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

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

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

Gas control is a person or persons who acquire and maintain data to remotely monitor and direct the flow of gas to meet design and contractual obligations, and to assist in detecting pipeline emergencies and initiating response.

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

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

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

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

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

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

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

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

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

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

SCADA is supervisory control and data acquisition. SCADA is a remote control system that allows the transmission of data from a remote site (e.g., a delivery point) to a central control location. SCADA systems are used to monitor and control flow, pressure, and other parameters of the pipeline system. SCADA systems may generate an alarm when an event has occurred or an unusual situation is developing.

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

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

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

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

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

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

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

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

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

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

Temperature (expressed in degrees Fahrenheit (^{o}F) unless otherwise stated). See also *Ambient temperature and Ground temperature*.

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

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

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

(a) Epoxy as used in epoxy fiberglass pipe, "Red Thread®" pipe, and fiber-reinforced pipe (FRP); and

(b) Unsaturated polyester as used in fiberglass composites for steel pipe repair sleeves, and cured-in-place (CIP).

Thickness. See *Nominal wall thickness*.

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

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

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

GLOSSARY OF COMMONLY USED ABBREVIATIONS

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

Abbreviation	Meaning
ABS	acrylonitrile-butadiene-styrene
ACVG	alternating current voltage gradient
ASV	automatic shutoff valve
BAP	baseline assessment plan
CAB	cellulose acetate butyrate
CDA	confirmatory direct assessment
CGI	combustible gas indicator
CIS	close-interval survey
CP	cathodic protection
DA	direct assessment
DCVG	direct current voltage gradient
ECDA	external corrosion direct assessment
EFV	excess flow valve
EFVB	excess flow valve – bypass (automatic reset)
EFVNB	excess flow valve – non-bypass (manual reset)
ERW	electric resistance welded
ESD	emergency shutdown
FAQ	frequently asked question
GIS	geographic information system
GPS	global positioning system
HCA	high consequence area
HDB	hydrostatic design basis
HFI	hydrogen flame ionization
IC	internal corrosion
ICDA	internal corrosion direct assessment
ICS	Incident Command System
ILI	In-line inspection
IMP	integrity management program
IR drop	voltage drop
LEL	lower explosive limit
LNG	liquefied natural gas
LPG	liquid petroleum gas
LTHS	long-term hydrostatic strength

GLOSSARY OF COMMOMLY USED ABBREVIATIONS (Continued)

Abbreviation	Meaning
MAOP	maximum allowable operating pressure
MRS	minimum required strength
NDE	nondestructive evaluation
NPS	nominal pipe size
O&M	operations and maintenance
OCS	outer continental shelf
OQ	operator qualification
PA	polyamide
P&M measures	preventive and mitigative measures
PDB	pressure design basis
PE	polyethylene
PIC	potential impact circle
PIR	potential impact radius
PVC	poly (vinyl chloride), also written as polyvinyl chloride
RCV	remote control valve
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
SCCDA	stress corrosion cracking direct assessment
SDB	strength design basis
SDR	standard dimension ratio
SMYS	specified minimum yield strength
USGS	United States Geological Survey
USCG	United States Coast Guard

TABLE 192.3i

§192.5
Class locations.

[Effective Date: 07/13/98]

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

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

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

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

(1) A Class 1 location is:

(i) An offshore area; or

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

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

(3) A Class 3 location is:

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

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

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

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

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

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

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

GUIDE MATERIAL

No guide material available at present.

§192.7

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

[Effective Date: 04/14/09]

(a) Any documents or portions thereof incorporated by reference in this part are included in this part as though set out in full. When only a portion of a document is referenced, the remainder is not incorporated in this part.

(b) All incorporated materials are available for inspection in the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC, 20590-0001 or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030 or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html*. These materials have been approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. In addition, the incorporated materials are available from the respective organizations listed in paragraph (c) (1) of this section.

(c) The full titles of documents incorporated by reference, in whole or in part, are provided herein. The numbers in parentheses indicate applicable editions. For each incorporated document, citations of all affected sections are provided. Earlier editions of currently listed documents or editions of documents listed in previous editions of 49 CFR part 192 may be used for materials and components designed, manufactured, or installed in accordance with these earlier documents at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR part 192 for a listing of the earlier listed editions or documents.

(1) Incorporated by reference (IBR). List of Organizations and Addresses:

A. Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, Houston, TX 77098.

B. American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005.

C. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.

D. ASME International (ASME), Three Park Avenue, New York, NY 10016–5990.

E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NE, Vienna, VA 22180.

F. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269–9101.

G. Plastics Pipe Institute, Inc. (PPI), 1825 Connecticut Avenue, NW, Suite 680, Washington, DC 20009.

H. NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084.

I. Gas Technology Institute (GTI), 1700 South Mount Prospect Road, Des Plaines, IL 60018.

(2) Documents incorporated by reference (Numbers in Parentheses Indicate Applicable Editions).

Source and name of referenced material	49 CFR reference
A. Pipeline Research Council International, Inc. (PRCI):	
(1) AGA Pipeline Research Committee, Project PR–3–805, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,'' (December 22, 1989). The RSTRENG program may be used for calculating remaining strength.	§§192.933(a); 192.485(c).
B. American Petroleum Institute (API):	
(1) ANSI/API Specification 5L/ISO 3183 ''Specification for Line Pipe,'' (43rd edition and errata, 2004, and 44th edition, 2007).	§§192.55(e); 192.112; 192.113; Item I of Appendix B.
(2) API Recommended Practice 5L1 ''Recommended Practice for Railroad Transportation of Line Pipe,'' (6th edition, 2002).	§192.65(a).
(3) API Specification 6D ''Pipeline Valves,'' (22nd edition, January 2002).	§192.145(a).
(4) API Recommended Practice 80, ''Guidelines for the Definition of Onshore Gas Gathering Lines,'' (1st edition, April 2000).	§§192.8(a); 192.8(a)(1); 192.8(a)(2); 192.8(a)(3); 192.8(a)(4).
(5) API 1104 ''Welding of Pipelines and Related Facilities,'' (19th edition 1999, including errata October 31, 2001; and 20th edition 2007, including errata 2008).	§§192.227(a); 192.229(c)(1); 192.241(c); Item II, and Appendix B.
(6) API Recommended Practice 1162 ''Public Awareness Programs for Pipeline Operators,'' (1st edition December 2003).	§§192.616(a); 192.616(b); 192.616(c).
C. American Society for Testing and Materials (ASTM):	
(1) ASTM A 53/A53M–04a (2004) ''Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless.''	§§192.113; Item I, Appendix B.
(2) ASTM A106/A106M-04b (2004) ''Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service.''	§§192.113; Item I, Appendix B.
(3) ASTM A333/A333M-05 (2005) ''Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service.''	§§192.113; Item I, Appendix B.
(4) ASTM A372/A372M-03 (2003) ''Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels.''	§192.177(b)(1).

Source and name of referenced material 49 CFR (Continued)	49 CFR reference (Continued)
(5) ASTM A381–96 (Reapproved 2001) ‘‘Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems.’’	§§192.113; Item I, Appendix B.
(6) ASTM Designation: A578/A578M–96 (Re-approved 2001) ‘‘Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications’’.	§§192.112(c)(2)(iii).
(7) ASTM A671-04 (2004) ‘‘Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures.’’	§§192.113; Item I, Appendix B.
(8) ASTM A672-96 (Reapproved 2001) ‘‘Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures.’’	§§192.113; Item I, Appendix B.
(9) ASTM A691-98 (Reapproved 2002) ‘‘Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures.’’	§§192.113; Item I, Appendix B.
(10) ASTM D638-03 ‘‘Standard Test Method for Tensile Properties of Plastics.’’	§§192.283(a)(3); 192.283(b)(1).
(11) ASTM D2513-87 ‘‘Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings.”	§192.63(a)(1).
(12) ASTM D2513-99 ‘‘Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings.”	§§192.191(b); 192.281(b)(2); 192.283(a)(1)(i); Item I, Appendix B.
(13) ASTM D2517-00 ‘‘Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings.’’	§§192.191(a); 192.281(d)(1); 192.283(a)(1)(ii); Item I, Appendix B.
(14) ASTM F1055-1998 ‘‘Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing.’’	§192.283(a)(1)(iii).
D. ASME International (ASME):	
(1) ASME B16.1-1998 ‘‘Cast Iron Pipe Flanges and Flanged Fittings.’’	§192.147(c).
(2) ASME B16.5-2003 (October 2004) ‘‘Pipe Flanges and Flanged Fittings.’’	§§192.147(a); 192.279.
(3) ASME B31G-1991 (Reaffirmed; 2004) ‘‘Manual for Determining the Remaining Strength of Corroded Pipelines.’’	§§192.485(c); 192.933(a).
(4) ASME B31.8-2003 (February 2004) ‘‘Gas Transmission and Distribution Piping Systems.’’	§192.619(a)(1)(i).

Source and name of referenced material (Continued)	49 CFR reference (Continued)
(5) ASME B31.8S-2004 ''Supplement to B31.8 on Managing System Integrity of Gas Pipelines.''	§§192.903(c); 192.907(b); 192.911, Introductory text; 192.911(i); 192.911(k); 192.911(l); 192.911(m); 192.913(a) Introductory text; 192.913(b)(1); 192.917(a) Introductory text; 192.917(b); 192.917(c); 192.917(e)(1); 192.917(e)(4); 192.921(a)(1); 192.923(b)(2); 192.923(b)(3); 192.925(b) Introductory text; 192.925(b)(1); 192.925(b)(2); 192.925(b)(3); 192.925(b)(4); 192.927(b); 192.927(c)(1)(i); 192.929(b)(1); 192.929(b)(2); 192.933(a); 192.933(d)(1); 192.933(d)(1)(i); 192.935(a); 192.935(b)(1)(iv); 192.937(c)(1); 192.939(a)(1)(i); 192.939(a)(1)(ii); 192.939(a)(3); 192.945(a).
(6) ASME Boiler and Pressure Vessel Code, Section I, "Rules for Construction of Power Boilers," (2004 edition, including addenda through July 1, 2005).	§192.153(a).
(7) ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, ''Rules for Construction of Pressure Vessels,'' (2004 edition, including addenda through July 1, 2005).	§§192.153(a); 192.153(b); 192.153(d); 192.165(b)(3).
(8) ASME Boiler and Pressure Vessel Code, Section VIII, Division 2, ''Rules for Construction of Pressure Vessels - Alternative Rules,'' (2004 edition, including addenda through July 1, 2005).	§§192.153(b); 192.165(b)(3).
(9) ASME Boiler and Pressure Vessel Code, Section IX, ''Welding and Brazing Qualifications,'' (2004 edition, including addenda through July 1, 2005).	§§192.227(a); Item II, Appendix B.
E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):	
(1) MSS SP44–1996 (Reaffirmed; 2001) ''Steel Pipe Line Flanges.''	§192.147(a).
(2) [Reserved].	
F. National Fire Protection Association (NFPA):	
(1) NFPA 30 (2003) ''Flammable and Combustible Liquids Code.''	§192.735(b).
(2) NFPA 58 (2004) ''Liquefied Petroleum Gas Code (LP–Gas Code).''	§§192.11(a); 192.11(b); 192.11(c).
(3) NFPA 59 (2004) ''Utility LP-Gas Plant Code."	§§192.11(a); 192.11(b); 192.11(c).
(4) NFPA 70 (2005) ''National Electrical Code.''	§§192.163(e); 192.189(c).

Source and name of referenced material (Continued)	49 CFR reference (Continued)
G. Plastics Pipe Institute, Inc. (PPI):	
(1) PPI TR–3/2004 (2004) ‘‘Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe.”	**§192.121.**
H. NACE International (NACE):	
(1) NACE Standard RP0502–2002 ‘‘Pipeline External Corrosion Direct Assessment Methodology.’’	**§§192.923(b)(1); 192.925(b) Introductory text; 192.925(b)(1); 192.925(b)(1)(ii); 192.925(b)(2) Introductory text; 192.925(b)(3) Introductory text; 192.925(b)(3)(ii); 192.925(b)(iv); 192.925(b)(4) Introductory text; 192.925(b)(4)(ii); 192.931(d); 192.935(b)(1)(iv); 192.939(a)(2).**
I. Gas Technology Institute (GTI):	
(1) GRI 02/0057 (2002) ‘‘Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology.’’	**§192.927(c)(2).**

[Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-51, 51 FR 15333, Apr. 23, 1986; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69 FR 54591, Sept. 9, 2004; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; Amdt. 192-99, 70 FR 28833, May 19, 2005 with Amdt. 192-99 Correction, 70 FR 35041, June 16, 2005; Amdt. 192-102, 71 FR 13289, Mar.15, 2006; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-103, 72 FR 4655, Feb. 1, 2007; RIN 2137-AE29, 73 FR 16562, Mar. 28, 2008; RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; RIN 2137-AE29 (#2), 74 FR 2889, Jan. 16, 2009; RIN 2137-AE42, 74 FR 17099, April 14, 2009]

GUIDE MATERIAL

Note: A “Stay of Enforcement Memorandum,” dated December 23, 2008, was issued from Jeffrey D. Wiese, Associate Administrator for Pipeline Safety, which addressed listed editions of API 5L and API 1104. It provides for use of later editions as follows:

- API Specification 5L, “Specification for Line Pipe” (44th edition, October 2007).
- API 1104, “Welding of Pipelines and Related Facilities” (20th edition, October 2005 including Errata/Addendum July 2007).

The document is available at www.phmsa.dot.gov/pipeline.

Additional standards and specifications recommended for use under this Guide, and the names and addresses of the sponsoring organizations, are shown in Guide Material Appendix G-192-1. See Guide Material Appendix G-192-1A for documents previously incorporated by reference in the Regulations.

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

Where:

P = Design pressure, gauge, psig (kPa).

S = For thermoplastic pipe, the HDB is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2004, *HDB/PDB/SDB/MRS Policies* (incorporated by reference, see §192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa). [Note: Arithmetic interpolation is not allowed for PA-11 pipe.]

t = Specified wall thickness, inches (mm).

D = Specified outside diameter, inches (mm).

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

DF = 0.32 or

= 0.40 for nominal pipe size (IPS or CTS) 4-inch or less, SDR-11 or greater (*i.e.*, thicker pipe wall), PA-11 pipe produced after January 23, 2009.

[Amdt. 192-31, 43 FR 13880, Apr. 3, 1978 with Amdt. 192-31 Correction, 43 FR 43308, Sept. 25, 1978; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; RIN 2137-AE26, 73 FR 79002, Dec. 24, 2008]

GUIDE MATERIAL

This guide material is under review following Amendment RIN 2137-AE26.

1 NATURAL GAS

(a) Hydrostatic Design Basis (HDB) values are awarded by the Hydrostatic Stress Board (HSB) of the Plastics Pipe Institute (PPI) and are listed in PPI TR-4, which can be accessed at www.plasticpipe.org.

(b) ASTM D2513 requires elevated temperature HDB listings for plastic piping materials used at temperatures above 73 °F. PPI publishes elevated temperature HDB values for PE and PA materials in TR-4.

(c) Magnetically-filled PE (reference ASTM D2513, Annex A.6) is considered as either PE 2406 or PE 3408 material.

(d) Long-term hydrostatic strength (LTHS) for reinforced thermosetting plastic covered by ASTM D2517 is 11,000 psi.

(e) HDB values apply only to materials meeting all the requirements of ASTM D2513 and are based on engineering test data analyzed in accordance with ASTM D2837, "Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products."

(f) HDB values at 73 °F for thermoplastic materials covered by ASTM D2513 are listed in Table 192.121i. The values used in the design formula for thermoplastic materials are actually HDB values that are a categorized value of the long-term hydrostatic strength.

Pipe Material	HDB @ 73 °F, psi
PA 32312 (PA 11)	2500
PE 2406	1250
PE 3408	1600
PVC Type I, Grade 1, Class 12454B (PVC 1120)*	4000
PVC Type II, Grade 1, Class 1433D (PVC 2116)*	3200
* Editions of ASTM D2513 issued after 2001 no longer permit use of PVC piping for new gas piping installations, but do specify that it may be used for repair and maintenance of existing PVC gas piping. The Regulations may continue to reference an edition of ASTM D2513 earlier than 2001. The operator is advised to check §192.7.	

TABLE 192.121i

2 PETROLEUM GASES

PE and PA materials listed in ASTM D2513 may be used for liquid petroleum gas (LPG) piping applications. NFPA 58 (referenced by §192.7) prescribes the following:

(a) PA may be used in liquid or vapor LPG systems up to the design pressure of the piping material. PPI recommends a chemical derating factor of 1.0 (no derating) for PA 11 piping.
(b) PE, when recommended by the manufacturer, may be used in vapor-only LPG systems up to 30 psig pressure. PPI recommends a 0.5 chemical derating factor for the use of PE piping.
(c) PVC is not permitted.

Some information on the strengths of polyethylenes with propane is given in PPI TR-22, "Polyethylene Piping Distribution Systems for Components of Liquid Petroleum Gases." See guide material under §192.123.

3 MINIMUM REQUIRED WALL THICKNESS

The minimum wall thickness (t_m) for a given design pressure is determined from the formula below. Also, see §192.123(c) and (d) plus 3 of the guide material under §192.123.

$$t_m = \frac{PD}{(P + 0.64\,S)}$$

Where:

P = Design pressure, gauge, kPa (psi)
D = Specified outside diameter, mm (in.)
S = The long-term hydrostatic strength, for thermoplastic pipe, kPa (psi) determined at 23 °C (73 °F), 38 °C (100 °F), 49 °C (120 °F), or 60 °C (140 °F); for reinforced thermosetting pipe, 75,800 kPa (11,000 psi)

4 INTERPOLATION OF HYDROSTATIC DESIGN BASIS (HDB) VALUES

(a) For thermoplastic pipe that is to be installed at a service temperature greater than 73 ºF and less than that at which the next HDB has been established, the HDB at the anticipated service temperature can be determined by interpolation. The pipe manufacturer should be consulted for assistance in determining an interpolated HDB.

§192.275
Cast iron pipe.
[Effective Date: 03/08/89]

(a) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

(b) Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

(c) Cast iron pipe may not be joined by threaded joints.

(d) Cast iron pipe may not be joined by brazing.

[Amdt. 192-62, 54 FR 5625, Feb. 6, 1989]

GUIDE MATERIAL

No guide material necessary.

§192.277
Ductile iron pipe.
[Effective Date: 03/08/89]

(a) Ductile iron pipe may not be joined by threaded joints.

(b) Ductile iron pipe may not be joined by brazing.

[Amdt. 192-62, 54 FR 5625, Feb. 6, 1989]

GUIDE MATERIAL

No guide material necessary.

§192.279
Copper pipe.
[Effective Date: 04/19/93]

Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

[Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993]

GUIDE MATERIAL

Note: Table C1 has been deleted from the 2003 edition of ASME B16.5. The same information about wall thickness and size can be found in ASME B36.10M. Reference ASME B36.10M to determine the equivalent minimum wall thickness for threading of copper pipe.

(a) Copper pipe may be joined by a mechanical joint or a brazed or soldered lap joint. The filler material used for brazing should be a copper-phosphorous or a silver base alloy.

(b) Butt welds should not be used for joining copper pipe or copper tubing.

§192.281
Plastic pipe.

[Effective Date: 07/08/96]

(a) *General*. A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints*. Each solvent cement joint on plastic pipe must comply with the following:

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

(2) The solvent cement must conform to ASTM Designation D 2513.

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

(c) *Heat-fusion joints*. Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

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

(d) *Adhesive joints*. Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM Designation D 2517.

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints*. Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

[Amdt. 192-34, 44 FR 42968, July 23, 1979 with Amdt. 192-34 Correction, 44 FR 50841, Aug. 30, 1979 and Amdt. 192-34 Correction, 44 FR 57100, Oct. 4, 1979; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996]

GUIDE MATERIAL

1 INTRODUCTION (Plastic-to-plastic and plastic-to-metal)

To achieve sound joints in plastic piping requires skillful application of qualified procedures and the use of proper materials and equipment in good condition. Joints should be made by personnel who are qualified in the written procedures required for the type of joint involved.

2 GENERAL (Plastic-to-plastic)

Plastic piping is joined by several material-specific joining methods including solvent cement, heat fusion, and adhesives as described below. All plastic piping materials may be joined by mechanical methods. The Regulations require that the joining procedures be qualified and that joining personnel and inspectors be trained and qualified. (See §§192.281, 192.283, 192.285, and 192.287.)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(d) Square cut ends, free of burrs, are required for a proper joint.
(e) The mating surfaces should be clean, dry, and free of material which might be detrimental to the joint.
(f) The potential effect of drag force (the force required to initiate pipe movement) during butt fusion should be considered to ensure proper fusion pressure.
(g) Other recommendations for making heat-fusion joints may be found in ASTM D 2657.
(h) PE piping of different compounds or grades can be heat fused to each other. Such joining should not be undertaken indiscriminately, and should be undertaken only when qualified procedures for joining the specific compounds are used. Suggested references are as follows.
  (1) PPI TN-13, "General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings."
  (2) PPI TR-33, "Generic Butt Fusion Joining Procedure for Polyethylene Gas Pipe."
  (3) PPI TR-41, "Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping."
(i) Rain, cold, and windy weather conditions can influence fusion quality. Modification of the recommended heating time in the procedure should be given consideration during such conditions.
(j) For hot taps on PE, see guide material under §192.123.
(k) The condition of equipment for heat fusing PE must conform to the equipment manufacturer's recommended tolerances for acceptable wear of critical components. The use of damaged or worn equipment may result in fusion joints that are weak or out of alignment. The frequency of inspection should be determined by the operator based on equipment usage, equipment age and condition, and manufacturer's recommendation. See Guide Material Appendix G-192-20 for a sample inspection form.

3.3 Heat fusion by electrofusion. (Plastic-to-plastic)
(a) Sections 192.273 and 192.283 require that procedures for making joints other than by welding be written and qualified. Each electrofusion equipment manufacturer is a source of appropriate procedures for their respective system. The operator should check state requirements on the use of electrofusion. Generally each procedure should contain some or all of the following elements:
  (1) *Couplings.*
    (i) The pipe should be cut at a square angle.
    (ii) The pipe should be marked with the proper stab depth for the fitting.
    (iii) Surface oxidation should be removed from the area of the pipe to be fused, up to the stab-depth marks, using the tool specified in the qualified procedure.
    (iv) One end of the pipe should be secured in an appropriate clamping device, the fitting slid onto pipe, the second piece of pipe placed into clamp, and the fitting slid to final position onto each pipe so it is properly aligned. Insertion up to the stab-depth marks should be ensured.
    (v) The control box should be tested for proper function.
    (vi) The fitting should be connected to the fusion control box and the cycle activated. The fitting should be left in the clamp until cooling has been completed.
    (vii) The joint should be inspected in accordance with §192.273.
  (2) *Sidewall fittings.*
    (i) Determine the pipe area where the fitting is to be fused.
    (ii) All surface oxidation should be removed from the pipe in the area to be fused using the tool specified in the qualified procedure.
    (iii) The fitting should be positioned and clamped in the cleaned area.
    (iv) The control box should be tested for proper function.
    (v) The fitting should be connected to the fusion control box and the cycle activated. The fitting should be left in the clamp until cooling has been completed.
    (vi) The joint should be inspected in accordance with §192.273.
(b) ASTM F1055 and the following are references for joining plastic pipe by electrofusion.
  (1) ASTM F1290, "Standard Practice for Electrofusion Joining Polyolefin Pipe and Fittings."
  (2) PPI Technical Committee Project 141, "Standard Practice for Electrofusion Joining Polyolefin Pipe and Fittings."

(3) For procedures intended for nonlateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference, *see* §192.7), except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical joints.* Before any written procedure established under §192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D638 (except for conditioning), (incorporated by reference, *see* §192.7).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 0.20 in (5.0 mm) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 4 inches (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 ^{o}F (38 ^{o}C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

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

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

[Issued by Amdt. 192-34, 44 FR 42968, July 23, 1979 with Amdt. 192-34 Time Ext., 44 FR 50841, Aug. 30, 1979, Amdt. 192-34 Time Ext., 44 FR 57100, Oct. 4, 1979, Amdt. 192-34A, 45 FR 9931, Feb. 14, 1980, Amdt. 192-34B, 46 FR 39, Jan. 2, 1981, Amdt. 192-34 Correction, 47 FR 32720, July 29, 1982 and Amdt. 192-34 Correction, 47 FR 49973, Nov. 4, 1982; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85,63 FR 37500, July 13, 1998; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69 FR 54591, Sept. 9, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006]

GUIDE MATERIAL

1 WRITTEN PROCEDURES

(a) An operator may elect to develop and qualify joining procedures or may follow the joining procedures qualified by piping or fitting manufacturers. In either instance, the operator is responsible for ensuring that the joining procedure used is qualified in accordance with the requirements of §192.283.

(b) When a manufacturer's qualified joining procedure is used, the manufacturer should supply written procedures, including pictures, demonstrating the appearance of satisfactory joints. Written procedures for fitting installation are often packaged with each fitting.

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

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

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

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

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

(i) Plastic compound or compounds.
(ii) Joint design.
(iii) Size and thickness range.
(iv) Method of joining.
(v) Curing or set-up time.
(vi) Temperature limits.
(vii) Temperature of the heating tool.
(viii) Proper end finishing.
(ix) Tools and equipment.
(x) Joining or repair technique. See 3.2 of the guide material under §192.281.

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

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

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

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

(2) *Qualification.* To qualify the procedure specification, test assemblies of joints or repairs should be made in accordance with the procedure specifications and tested in accordance with 2.2 below. The test assemblies may be restrained to the same extent that they would be in service. These assemblies should be sectioned or dismantled to inspect for damage to the plastic pipe. The procedure should be rejected if there is evidence of damage that would reduce the service life of an installed joint or repair.

2.2 Test Requirements. (Plastic-to-plastic and plastic-to-metal)

Test assemblies should successfully meet the following requirements.

(a) Leak test. An assembly should not leak when subjected to a stand-up pressure test with air or gas.
(b) Short-term burst test. An assembly should meet the minimum burst requirements of ASTM D 2513 or ASTM D2517, whichever is applicable, for the specific kind and size of plastic pipe used in the assembly.
(c) Sustained-pressure test. An assembly should not fail when subjected to a sustained pressure test, such as the 1000 hr test described in ASTM D2513 or ASTM D2517 (whichever is applicable), for the specific kind and size of plastic pipe used in the assembly.
(d) Inspection. An assembly should be subjected to suitable nondestructive or destructive inspection to determine if the bonded area is substantially equivalent to the intended bond area.

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

(b) Offshore.
(1) The surface of the corrosion preventive coating should be inspected before weight-coating.
(2) The weight-coating should be inspected before the pipe is welded.

2 JOINT RESTRAINT

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

2.2 Special considerations.
Cast iron pipe installed in unstable soils should be provided with suitable supports. See guide material under §192.755.

3 BACKFILLING

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

3.2 Backfill material.
(a) General. If there are large rocks in the material to be used for backfill, care should be used to prevent damage to the coating. This may be accomplished by the use of rock shield material or by making an initial fill with enough rock-free material to prevent damage.
(b) Effects on cathodic protection (CP) system. Consideration should be given to the possible shielding effects on CP currents that may occur from the installation of non-conductive materials, such as rock shielding and padding.

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

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

4 ALTERNATIVE INSTALLATION METHODS

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

§192.321
Installation of plastic pipe.

[Effective Date: 07/14/04]

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

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

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

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inch (2.29 millimeters), except that pipe with an outside diameter of 0.875 inch (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inch (1.58 millimeters).

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

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

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

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

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

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

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

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

(2) Protected from ultraviolet radiation; and

(3) Not allowed to exceed the pipe temperature limits specified in §192.123.

[Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-94, 69 FR 32886, June 14, 2004]

GUIDE MATERIAL

1 GENERAL PRECAUTIONS

1.1 Handling.

Care should be taken to avoid rough handling of plastic pipe. It should not be dropped or have other objects dropped upon it, nor should it be pushed or pulled over sharp projections. Caution should be taken to prevent kinking or buckling. Any kinks or buckles that occur should be cut out as a cylinder.

1.2 Considerations to minimize damage by outside forces.

See Guide Material Appendix G-192-13.

§192.361

Service lines: Installation.

[Effective Date: 10/15/03]

(a) *Depth*. Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) *Support and backfill*. Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) *Grading for drainage*. Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) *Protection against piping strain and external loading*. Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) *Installation of service lines into buildings*. Each underground service line installed below grade through the outer foundation wall of a building must --

(1) In the case of a metal service line, be protected against corrosion;

(2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and

(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) *Installation of service lines under buildings*. Where an underground service line is installed under a building --

(1) It must be encased in a gas tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

(g) *Locating underground service lines.* Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with §192.321(e).

[Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003

GUIDE MATERIAL

1 COVER CONSIDERATIONS

(a) Where cover requirements cannot be met due to existing substructures, the portions of the service lines which could be subjected to superimposed loads should be cased or bridged, or the pipe should be appropriately strengthened.

(b) See Guide Material Appendix G-192-13 for additional cover considerations and for considerations to minimize damage by outside forces.

2 COATED STEEL SERVICE LINES IN BORES

2.1 General.
When coated steel pipe is to be installed in a bore, care should be taken to prevent damage to the coating during installation.

2.2 Boring or driving.
(a) When a coated steel pipeline is to be installed by boring or driving, the pipe should not be used as the bore pipe or drive pipe unless the coating is sufficiently durable to withstand the operation. If considering retaining the bored or driven pipe as the carrier pipe, it should be demonstrable that the coating is sufficiently durable for the anticipated soil conditions and installation forces. Where significant damage to the coating may result from boring or driving, the coated pipeline should be installed in an oversize bore or in casing pipe of sufficient diameter to accommodate the pipe.
(b) See Guide Material Appendix G-192-6 for damage prevention considerations while performing directional drilling or using other trenchless technologies.
(c) See Guide Material Appendices G-192-15A and G-192-15B for additional considerations for horizontal directional drilling to install steel pipelines and plastic pipelines, respectively.

2.3 Special consideration.
In exceptionally rocky soil, and if significant damage to the coating is likely, coated pipe should not be inserted through an open bore.

3 PLASTIC SERVICE LINES

3.1 Main connection.
The excavation below the piping at the main connection should be tamped using compactable material. Where non-compactable material is present, such as very wet mud, it may be necessary to replace it with compactable material.

The connection between a PE service line and the main is particularly susceptible to excessive shear stresses due to the design of the joint. Consideration should be made in the joint design to determine if a protective sleeve is necessary, in addition to providing adequate backfill and compaction around the transition area, to reduce excessive bending and shear stresses. Protective sleeves that are designed to mitigate the stresses imposed onto the plastic pipe in the transition areas should be considered if undue stresses at this joint are anticipated, or if recommended by the manufacturer. For protective sleeves, see guide material under §192.367. For guide material specific to protective bridging sleeves, see Figures 192.361A and 192.361B.

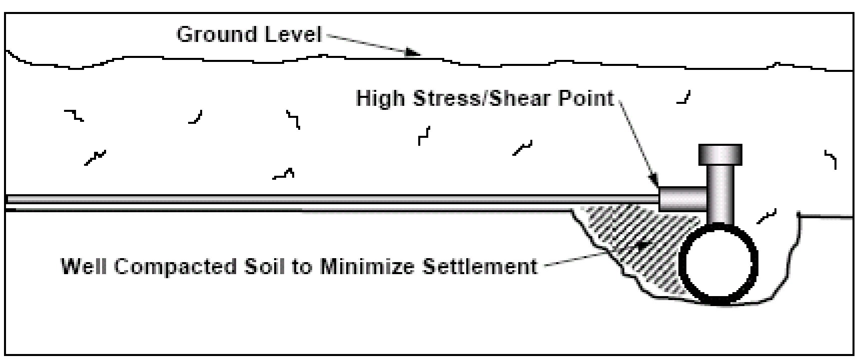

FIGURE 192.361A
Tapping Tee Installation with Compaction of Soil

GUIDE MATERIAL

The operator should make certain that the types of service-line valves installed on high-pressure service lines are suitable. This may be accomplished by making tests or by reviewing the tests made by the manufacturer.

See guide material under §192.381 for considerations on using excess flow valves (EFVs).

§192.365
Service lines: Location of valves.

[Effective Date: 11/12/70]

(a) *Relation to regulator or meter*. Each service line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

(b) *Outside valves*. Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) *Underground valves*. Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

GUIDE MATERIAL

When installing a shut-off valve, the operator should consider the access to and operability of the valve under all reasonably anticipated conditions including areas prone to high water or flooding conditions.

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

[Effective Date: 04/26/96]

(a) *Location*. Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

(b) *Compression-type connection to main*. Each compression-type service line to main connection must--

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

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

[Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996]

GUIDE MATERIAL

1 MAIN CONNECTION AND PE PIPING

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

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

1.3 Protective sleeves.
(a) Purpose.
Protective sleeves mitigate excessive bending and shear stresses imposed on the plastic pipe at transition areas. Protective sleeve installations are in addition to providing adequate backfill and compaction around transition areas.
(b) Design.
(1) The protective sleeve should be designed to fully support the PE pipe in the joint area at the service tee.
(2) The protective sleeve should be of adequate length and inside diameter to ensure that the manufacturer’s minimum bend radius is not exceeded.
(3) The annulus between both the protective sleeve and the service tee, and the PE service line, should be of such fit to avoid overstressing the joint due to anticipated earth settlement after installation.
(4) Protective sleeves, supplied by several manufacturers, are typically lengths of either PE or PVC pipe.

1.4 Bending at joints in PE piping.
Due to the nature of installation, the service tee connection can experience excessive bending forces that are transmitted to the piping at the service tee joint.
(a) Bending of PE piping can overstress the joints, which can lead to premature failures. These concerns are heightened when making mechanical joints from steel service tees to PE pipe as the transition is from a rigid steel coupling to a flexible pipe, concentrating stresses at the transition area.
(b) The minimum bend radii recommendations received from various PE piping manufacturers range from 90 to 125 pipe diameters depending on the PE used.

Example: 1” IPS (1.315” OD) PE piping containing a fitting in a bend should be bent at a bend radius no tighter than 118” to 164” depending on the specific pipe manufacturer's recommendation. (Where, 1.315” x 90 = 118”; 1.315” x 125 = 164”.) Contact the piping manufacturer for specific minimum bend radius recommendations.

1.5 Other considerations.
See guide material under §192.361.

1.3 *Alternate Method*.

For conditions of low stress level, the following method may be used. An MAOP, not to exceed the established MAOP, may be determined by the following formula:

$$P = \frac{2St_rT}{D}$$

Where:

P	=	MAOP (not to exceed established MAOP), psig
S	=	hoop stress, psig
t_r	=	actual remaining wall thickness at point of deepest corrosion, inches
T	=	temperature derating factor, see §192.115
D	=	pipe outside diameter, inches

S must not exceed 72 percent of SMYS in Class 1 locations, 60 percent in Class 2 locations, 50 percent in Class 3 locations, and 40 percent in Class 4 locations.

2 REPAIR OR REPLACEMENT

If a pipeline has an area of external corrosion that disqualifies it for service at the established MAOP, or if the MAOP cannot be reduced to the indicated safe level, it should be repaired or replaced. For acceptable methods of repair, see 3 below and §§192.703, 192.711(b), 192.713, and 192.717.

3 RELIABLE ENGINEERING TESTS AND ANALYSES (§192.485(a))

Reliable engineering tests and analyses demonstrate compliance with a performance standard. Operators may conduct their own tests and analyses; or, they may choose to accept testing and analyses done by manufacturers, trade associations, consultants, or other operators. The engineering tests and analyses should:

(a) Include the following items, as needed, to achieve satisfactory precision.
   (1) Concise and orderly procedures for conducting tests and analyses.
   (2) Listing of equipment needed.
   (3) Descriptions of test specimens.
   (4) Required calculations.
(b) Exhibit sound engineering practices, which may include the following.
   (1) Knowledge and experience relating to the subject area.
   (2) Data evaluation and statistical analysis.
   (3) Assessment of test results to verify an analytical model.
   (4) Application of scientific principles.

§192.487
Remedial measures: Distribution lines other than cast iron or ductile iron lines.

[Effective Date: 01/13/00]

(a) *General corrosion*. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting*. Except for cast iron or ductile iron pipe, each segment of

distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999]

GUIDE MATERIAL

1 Pitting

Where inspection indicates that pitting exists which may result in leakage, the operator should consider the following.

(a) Examining the corrosion history and leak records to see if the additional information from this examination warrants replacement of a segment of this distribution pipe.
(b) Installing leak clamps on or over the pits.
(c) Cleaning and coating the exposed piping in accordance with §192.461.
(d) Applying cathodic protection (CP).
(e) Installing test wires for monitoring CP.

2 RELIABLE ENGINEERING TESTS AND ANALYSES

See guide material under §192.485.

§192.489

Remedial measures: Cast iron and ductile iron pipelines.

[Effective Date: 08/01/71]

(a) *General graphitization*. Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.

(b) *Localized graphitization*. Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

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

GUIDE MATERIAL

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

(b) For ductile iron, see 5.3(b) of Guide Material Appendix G-192-18.

1.4 Testing history review.

(a) Segments of pipeline constructed on or after September 12, 1970.

(1) Test pressure, test media and test duration.
(2) Date test accepted.
(3) Cause of any test failure (if known).
(4) Repairs made to leaks, damaged pipe, and welds.

(b) Segments of pipeline constructed before September 12, 1970.

(1) Highest pressure to which each test segment was strength tested, or in lieu thereof, pressure of a strength test sufficient to serve as an acceptable test pressure for the proposed maximum allowable operating pressure.
(2) Approximate date of test.
(3) Cause of any test failure (if known).
(4) Repairs made to leaks, damaged pipe, and welds.

§192.557

Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

[Effective Date: 07/13/98]

(a) Unless the requirements of this section have been met, no person may subject --

(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or

(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall --

(1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;

(3) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

(4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation;

(5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

(6) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.

(c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i. (69 kPa) gage or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b) (6) of this section apply, there must be at least two approximately equal incremental increases.

(d) If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed

increased pressure, the following procedures must be followed:

(1) In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile pipe was laid without blocks with tamped backfill.

(2) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and shall use the greatest cover measured.

(3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Pipe size inches (millimeters)	Allowance inches (millimeters)		
	Cast iron pipe		Ductile iron pipe
	Pit cast pipe	Centrifugally cast pipe	
3 to 8 (76 to 203)	0.075 (1.91)	0.065 (1.65)	0.065 (1.65)
10 to 12 (254 to 305)	0.08 (2.03)	0.07 (1.78)	0.07 (1.78)
14 to 24 (356 to 610)	0.08 (2.03)	0.08 (2.03)	0.075 (1.91)
30 to 42 (762 to 1067)	0.09 (2.29)	0.09 (2.29)	0.075 (1.91)
48 (1219)	0.09 (2.29)	0.09 (2.29)	0.08 (2.03)
54 to 60 (1372 to 1524)	0.09 (2.29)	-----	-----

(4) For a cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 p.s.i. (76 MPa) gage and a modulus of rupture of 31,000 p.s.i. (214 Mpa) gage.

[Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 PLANNING AND INVESTIGATIVE STUDIES

1.1 Feasibility.

After developing a written plan in accordance with the requirements of §192.553(c), an evaluation of the adequacy of the system design and the feasibility of uprating at the increased pressure levels should include the following.

(a) A review of the pressure ratings of the pipeline system components, such as valves, fittings, pipe, and regulators.
(b) In the case of cast iron, a review of the §192.753 requirements regarding joint retention and pressure limits when deciding on the MAOP uprating.
(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) A review of leakage, corrosion, operating pressure, and maintenance history to ascertain the present condition of facilities.
(e) An analysis of the effect of the ultimate separation and uprating on adjoining facilities.

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 Leakage survey.

A leakage 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.

GUIDE MATERIAL

1 IDENTIFICATION

1.1 Criteria for identifying pipelines.

Operators are required to identify their pipelines located in the Gulf of Mexico and its inlets, where the water is less than 15 feet deep as measured from mean low water. Rivers, tidal marshes, lakes, and canals are excluded. Operators may determine where the water depth of the Gulf of Mexico and its inlets is 15 feet or less by referencing USGS maps or depth charts, USCG water depth maps or tables, or their own construction and maintenance records.

1.2 Assessing risk of identified pipelines.

Operators should assess the risk of such pipelines being exposed or being a hazard to navigation by considering the following.

(a) Types of vessels navigating the water body.
(b) Traffic density of vessels navigating the water body.
(c) Possible effects that hurricanes or other significant natural occurrences might have on pipeline depth of cover.
(d) History of pipeline damage from navigating vessels.
(e) Geological restrictions to navigation over the pipeline, such as the proximity of a land mass or the presence of water much shallower than 15 feet.
(f) Results of previous underwater inspections of the pipeline.
(g) Changing conditions of the sea floor, such as scouring, shifting, mudslides, collapsing, and silting.

2 INSPECTION

2.1 Inspection frequencies and prioritization.

(a) Operators may use the information obtained in 1.2 above to establish the frequency for inspecting each pipeline.
(b) Operators should prioritize the order in which the pipelines may be inspected and inspect those of perceived higher risk first, and possibly more frequently.
(c) Pipelines that operators determine are at risk of becoming a hazard to navigation or becoming exposed should be inspected more often, but operators should establish intervals for repeating inspections based upon the risks.

2.2 Inspection methods.

Operators may employ any suitable method, or a combination of methods, for underwater pipeline inspection based upon conditions required by a pipeline's specific environment. Operators should consider the following methods.

(a) Divers.
(b) Ultrasound or sidescan sonar.
(c) Remotely operated underwater inspection devices or vehicles (e.g., ROVs).
(d) Photography.
(e) Probing.

3 REPORTING (§192.612(c)(1))

In addition to the reporting requirements of §192.612(c)(1), an operator should also consider including the following.

(a) Latitude and longitude of the pipeline end points.
(b) Offshore area name.
(c) Offshore block number.
(d) Name of water body.
(e) Name of parish or county.
(f) Other pertinent information.

4 REMEDIAL ACTION

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

§192.613
Continuing surveillance.

[Effective Date: 11/12/70]

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

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

GUIDE MATERIAL

1 GENERAL

Continuing surveillance should be conducted so as 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) Effect 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.
(b) Periodic review and analysis of records, such as the following.
   (1) Patrols.
   (2) Leakage 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.

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 are subject to brittle-like cracking. This failure mode relates to a part-through crack initiating in the pipe wall followed by stable crack growth causing failure. These failures result in a very 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” piping manufactured by DuPont Company during 1971 and 1972. To determine if the “Aldyl A” pipe has low-ductile inner wall, see paragraph (f).
  (3) PE gas pipe designated PE 3306.
(c) Conditions that may cause these types of materials to fail prematurely include the following.
  (1) Inadequate support and backfill during installation.
  (2) Tree root or rock impingement.
  (3) Shear and bending stresses due to differential settlement resulting from factors such as:
    (i) Excavation in close proximity to PE piping.
    (ii) Directional drilling in close proximity to PE piping.
    (iii) Frost heave.
  (4) Bending stresses due to pipe installations with bends exceeding recommended practices.
  (5) Stresses where the pipe has been squeezed off.
(d) Each operator that has these older PE pipelines should consider the following practices.
  (1) Review system records to determine if any known susceptible materials have been installed in the system.
  (2) Perform more frequent inspection and leak surveys on systems that have exhibited brittle-like cracking failures of known susceptible materials.
  (3) Collect failure samples of PE piping exhibiting brittle-like cracking.
  (4) Record the print line from any piping that has been involved in a failure. The print line information can be used to identify the resin, manufacturer, and year of manufacture for plastic piping.
  (5) For systems where there is no record of the piping material, consider recording print line data when piping is excavated for other reasons. Recording the print line data can aid in establishing the type and extent of PE piping used in the system.
  (6) Develop procedures for taking appropriate action, including pipe replacement, to mitigate potential pipe failures.
  (7) Use a consistent record format to collect data on system failures. It is recommended that operators use a standard industry form developed for gathering data on plastic pipe failures to help trend and evaluate the extent of plastic pipe performance problems. For information about such form, visit the AGA website at www.aga.org under "Operations and Engineering/Plastic Piping Data Project."

(e) For those pipeline systems that contain products manufactured by Century Utility Products, Inc. between 1970 and 1973, the systems should be monitored and necessary replacements made for system integrity and public safety.
(f) An operator can determine if the PE 2306 "Aldyl A" piping manufactured by DuPont Company during 1971 and 1972 has low-ductile inner wall by using the following procedure.
  (1) Cut a ½-inch ring from the pipe.
  (2) Cut the ring at one point.
  (3) Reverse bend the ring, exposing the inner surface of the pipe.
  (4) Bend back the ring until the outer surfaces of the pipe (or cut ends) touch.
  (5) Cracking on the inner surface of the ring in the bend area indicates low-ductile inner wall.
(g) References concerning brittle-like cracking in PE materials include the following.
  (1) NTSB Reports PAB-98-02 and SIR-98-01, available at www.ntsb.gov/publictn.
  (2) OPS Advisory Bulletins (see Guide Material Appendix G-192-1, Section 2) as follows.
    (i) ADB-99-01 (64 FR 12211, Mar. 11, 1999).
    (ii) ADB-99-02 (64 FR 12212, Mar. 11, 1999).
    (iii) ADB-02-07 (67 FR 70806, Nov. 26, 2002 with Correction, 67 FR 72027, Dec. 3, 2002).
  (3) "Correlating Aldyl 'A' and Century PE Pipe Rate Process Method Projections with Actual Field Performance," E.F. Palermo, Ph.D, Plastics Pipes XII Conference, April 2004, available at www.aga.org/gptc.

4 STEEL TRANSMISSION LINES -- STRESS CORROSION CRACKING (SCC)

4.1 SCC.

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

(a) Types of SCC.
Two types of SCC may be found on underground steel pipe.
  (1) "Near-neutral-pH SCC," also known as low-pH or non-classical SCC, with the following basic characteristics.
    (i) Transgranular.
    (ii) Limited branching.
    (iii) Associated with some corrosion of the crack walls and pipe surface.
    (iv) Associated with a near-neutral electrolyte (pH 6.0 to 8.0).
  (2) "High-pH SCC," also known as classical SCC, with the following basic characteristics.
    (i) Intergranular.
    (ii) Typically branched.
    (iii) Associated with an alkaline electrolyte (pH 9.0 to 11.0).

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

TYPICAL CHARACTERISTICS OF SCC IN PIPELINES

Factor	Near-neutral-pH SCC	High-pH SCC
Location	• Associated with specific terrain conditions, often alternate wet-dry soils, and soils that tend to disbond or damage coatings.	• Typically within 20 miles downstream of a compressor station. • Number of failures reduces markedly with increased distance from compressors and lower pipe temperature. • Associated with specific terrain conditions, often alternate wet-dry soils, and soils that tend to disbond or damage coatings.
Temperature	• No apparent correlation with temperature of pipe. • Appears to occur more frequently in the colder climates where CO_2 concentration in groundwater is higher.	• Growth rate increases exponentially with temperature increase.
Operating Pressure	• In excess of 60% SMYS.	• In excess of 60% SMYS.
Associated Electrolyte	• Dilute bicarbonate solution with a neutral pH in the range of 6.0 to 8.0.	• Concentrated carbonate-bicarbonate solution with an alkaline pH greater than 9.3.
Electrochemical Potential	• Free corrosion potential: –760 to –790 mV ($Cu/CuSO_4$). • Cathodic protection does not reach pipe surface at SCC sites.	• Free corrosion potential: –600 to –750 mV ($Cu/CuSO_4$). • Cathodic protection is effective to achieve these potentials.
Morphology	• Primarily transgranular (across the steel grains). • Wide cracks with evidence of substantial corrosion within crack side wall.	• Primarily intergranular (between the steel grains). • Narrow, tight cracks with almost no evidence of secondary corrosion within crack side wall.

TABLE 192.613i

(b) New pipelines.
The most effective method of preventing SCC on new pipelines is to apply a high-performance coating system (e.g., fusion-bonded epoxy, urethane, liquid epoxy, extruded polyethylene, multi-layer coating) to a properly prepared surface and then to apply cathodic protection.

(c) SCC susceptibility.
There are a number of approaches for assessing and prioritizing pipeline susceptibility to SCC, and no single method is recommended over another. What is important is that a consistent approach be used that includes both technical and environmental factors that contribute to reducing the overall risk of a potential SCC occurrence. The following characterizations should be used to evaluate SCC susceptibility.

(1) Failure history -- Identify past SCC failures.
(2) Coating type (e.g., coal-tar, tape) -- Address condition and type of coating, including the type of surface preparation on the pipe prior to coating application.
(3) Pipe material (e.g., API grades, pipe mill).
(4) Operations (e.g., pressure, temperature).

(5) Location -- Correlate the environmental conditions near the pipeline with the occurrence of SCC.
   (i) Use of soil models to correlate with potential coating disbondment segments.
   (ii) Drainage, local topography, soil disposition, and similar aspects of soil models, tied with time in service, are seen as predictors of potential coating failures.
(6) Age.
(7) Bellhole -- Trending analysis of buried pipe inspection reports to identify common characteristics in pipe with SCC compared with pipe having no SCC.
(8) Magnetic flux leakage ILI results.
(9) Other ILI results.
(10) Cathodic protection level -- Monitor CP voltage levels at locations with and without active SCC.
(11) Hydrostatic retest program – Testing pipe to determine presence of SCC.
   Note: If critical size cracks are present, a rupture of the line will likely occur.

(d) Follow-up actions for positive indications of SCC susceptibility.
A written inspection, examination, and evaluation plan should be prepared when pipelines are determined to be susceptible to SCC.
(1) *Inspection*.
   The inspection objectives are to conduct aboveground or other types of measurements to supplement, if needed, the data collected and analyzed to determine SCC susceptibility. This data should then be used to prioritize susceptible segments and to select the specific sites for direct examination. Inspection examples include the following.
   (i) Close-interval survey.
   (ii) Coating-fault survey.
   (iii) ILI geometry tool.
   (iv) ILI electromagnetic acoustical transducer tool.
   (v) Hydrostatic test.
(2) *Examination*.
   Examination should include procedures to field-verify sites selected for direct examination. Any SCC detected should be followed by an assessment of its severity, extent, and type at the individual dig-site.
(3) *Evaluation*.
   An operator's evaluation plan should address the following.
   (i) Method used to determine whether general SCC mitigation is required.
   (ii) Prioritize remedial action for defects that are not removed immediately.
   (iii) Evaluate the effectiveness of the SCC approach.

4.2 References.

(a) ASME B31.8S, Appendix A3.3, "Criteria and Risk Assessment."
(b) NACE Publication 35103, "External Stress Corrosion Cracking of Underground Pipelines."
(c) NACE RP0204, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology."
(d) National Energy Board (Canada), Report of the Inquiry MH-2-95, "Stress Corrosion Cracking on Canadian Oil and Gas Pipelines," December 1996.
(e) OPS Advisory Bulletin ADB-03-05 (68 FR 58166, Oct. 8, 2003; see Guide Material Appendix G-192-1, Section 2).
(f) OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study," Michael Baker, Jr., Inc., January 2005.

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 MINING ACTIVITIES

For pipelines affected by mining activities, see Guide Material Appendix G-192-13.

§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

(ii) In the case of blasting, any inspection must include leakage surveys.

(d) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines located offshore.

(2) Pipelines, other than those located offshore, in Class 1 or 2 locations until September 20, 1995.

(3) Pipelines to which access is physically controlled by the operator.

(e) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following:

(1) The requirement of paragraph (a) of this section that the damage prevention program be written; and

(2) The requirements of paragraphs (c)(1) and (c)(2) of this section.

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GUIDE MATERIAL

1 SCOPE

This guide material covers damage prevention programs for buried pipelines, excluding pipelines specified under §192.614(d) that are exempt from these requirements.

2 WRITTEN PROGRAM

Written procedures, when required, should state the purpose and objectives of the damage prevention program and provide methods to achieve them. For program content, operators should review applicable state and local one-call requirements. A reference for state requirements is the One Call Systems International (OCSI) Directory, which provides a summary of the damage prevention laws in each state. In addition, operators should review the Common Ground Alliance's "Best Practices" Guide. These references are available at www.commongroundalliance.com. The procedures should include the following.

2.1 Definition of excavation activities.

In defining excavation activities to be covered by the damage prevention program, the operator should review the definition in §192.614(a) and applicable state and local requirements.

2.2 One-call systems.

(a) A one-call system may exist that does not meet the qualification requirements of §192.614(b)(1) or (b)(2). If the operator participates in a non-qualified one-call system, either because a qualified one-call system does not cover the area or for any other reason, the operator should consider working with that one-call system to make it qualified.

(b) If a one-call system covering the operator's facilities does not exist, the operator should consider establishing a qualified one-call system with other underground facility operators.

(c) The operator is cautioned that satisfying the requirements of §192.614 may require more than participation in a one-call system. The operator should evaluate the services being provided by the one-call system to determine what additional measures may need to be taken to satisfy the requirements of §192.614.