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Chapter 301. Transportation of Hazardous Liquids by Pipeline [49 CFR Part 195]

Subchapter A. General [49 CFR Subpart A]

§30101. Scope [49 CFR Part 195 Subpart A]

A. This Subpart prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids or carbon dioxide. [49 CFR 195.0]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 18:861 (August 1992), LR 29:2804 (December 2003).

§30103. Which Pipelines are Covered by this Subpart? [49 CFR 195.1]

A. Covered. Except for the pipelines listed in Subsection B of this Section, this Subpart applies to pipeline facilities and the transportation of hazardous liquids or carbon dioxide associated with those facilities within the state of Louisiana, including the coastal zone limits. Covered pipelines include, but are not limited to: [49 CFR 195.1(a)]

1. any pipeline that transports a highly volatile liquid (HVL); [49 CFR 195.1(a)(1)]

2. any pipeline segment that crosses a waterway currently used for commercial navigation; [49 CFR 195.1(a)(2)]

3. except for a gathering line not covered by paragraph A.4 of this Section, any pipeline located in a rural or non-rural area of any diameter regardless of operating pressure; [49 CFR 195.1(a)(3)]

4. any of the following onshore gathering lines used for transportation of petroleum: [49 CFR 195.1(a)(4)]

a. a pipeline located in a non-rural area; [49 CFR 195.1(a)(4)(i)]

b. a regulated rural gathering line as provided in §30117; or [49 CFR 195.1(a)(4)(ii)]

c. a pipeline located in an inlet of the Gulf of Mexico as provided in §30413. [49 CFR 195.1(a)(4)(iii)]

5. for purposes of the reporting requirements in Subchapter B of this Subpart, any gathering line not already covered under Paragraphs A.1, 2, 3 or 4 of this Section. [49 CFR 195.1(a)(5)]

B. Excepted. This Subpart does not apply to any of the following: [49 CFR 195.1(b)]

1. transportation of a hazardous liquid transported in a gaseous state; [49 CFR 195.1(b)(1)]

2. except for the reporting requirements of Subchapter B of this Subpart see §30199, transportation of a hazardous liquid through a pipeline by gravity; [49 CFR 195.1(b)(2)]

3. transportation of a hazardous liquid through any of the following lowstress pipelines: [49 CFR 195.195.1(b)(3)]

a. a pipeline subject to safety regulations of the U.S. Coast Guard; or [49 CFR 195.1(b)(3)(i)]

b. a pipeline that serves refining, manufacturing, or truck, rail, or vessel terminal facilities, if the pipeline is less than one mile long (measured outside facility grounds) and does not cross an offshore area or a waterway currently used for commercial navigation; [49 CFR 195.1(b)(3)(ii)]

4. transportation of petroleum through an onshore rural gathering line that does not meet the definition of a "regulated rural gathering line" as provided in §30117. This exception does not apply to gathering lines in the inlets of the Gulf of Mexico subject to §30413; [49 CFR 195.1(b)(4)]

5. transportation of hazardous liquid or carbon dioxide in an offshore pipeline in State waters where the pipeline is located upstream from the outlet flange of the following farthest downstream facility: The facility where hydrocarbons or carbon dioxide are produced or the facility where produced hydrocarbons or carbon dioxide are first separated, dehydrated, or otherwise processed; [49 CFR 195.1(b)(5)]

6. transportation of hazardous liquid or carbon dioxide in a pipeline on the OCS where the pipeline is located upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator; [49 CFR 195.1(b)(6)]

7. a pipeline segment upstream (generally seaward) of the last valve on the last production facility on the OCS where a pipeline on the OCS is producer-operated and crosses into State waters without first connecting to a transporting operator's facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. A producing operator of a segment falling within this exception may petition the Administrator, under §190.9 of this chapter, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance; [49 CFR 195.1(b)(7)]

8. transportation of a hazardous liquid or carbon dioxide through onshore production (including flow lines),

refining, or manufacturing facilities or storage or in-plant piping systems associated with such facilities; [49 CFR 195.1(b)(8)]

9. transportation of a hazardous liquid or carbon dioxide: [49 CFR 195.1(b)(9)]

a. by vessel, aircraft, tank truck, tank car, or other non-pipeline mode of transportation; or [49 CFR 195.1(b)(9)(i)]

b. through facilities located on the grounds of a materials transportation terminal if the facilities are used exclusively to transfer hazardous liquid or carbon dioxide between non-pipeline modes of transportation or between a non-pipeline mode and a pipeline. These facilities do not include any device and associated piping that are necessary to control pressure in the pipeline under §30406.B; or [49 CFR 195.1(b)(9)(ii)]

10. transportation of carbon dioxide downstream from the applicable following point: [49 CFR 195.1(b)(10)]

a. the inlet of a compressor used in the injection of carbon dioxide for oil recovery operations, or the point where recycled carbon dioxide enters the injection system, whichever is farther upstream; or [49 CFR 195.1(b)(10)(i)]

b. the connection of the first branch pipeline in the production field where the pipeline transports carbon dioxide to an injection well or to a header or manifold from which a pipeline branches to an injection well. [49 CFR 195.1(b)(10)(ii)]

C. Breakout Tanks. Breakout tanks subject to this Subpart must comply with requirements that apply specifically to breakout tanks and, to the extent applicable, with requirements that apply to pipeline systems and pipeline facilities. If a conflict exists between a requirement that applies specifically to breakout tanks and a requirement that applies to pipeline systems or pipeline facilities, the requirement that applies specifically to breakout tanks prevails. Anhydrous ammonia breakout tanks need not comply with Sections §30189.B, 30205.B, 30264.B and E, 30307, 30428.C and D, and 30432.B and C. [49 CFR 195.1(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 18:861 (August 1992), LR 20:439 (1994), LR 21:814 (August 1995), LR 27:1523 (September 2001), LR 29:2804 (December 2003), LR 33:466 (March 2007), LR 35:2791 (December 2009), LR 38:99 (January 2012), LR 46:1604 (November 2020).

§30105. Definitions [49 CFR 195.2]

A. As used in this Subpart:

Abandoned—permanently removed from service.

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

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

Barrel—a unit of measurement equal to 42 U.S. standard gallons.

Breakout Tank—a tank used to:

a. relieve surges in a hazardous liquids pipeline system; or

b. receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline.

Carbon Dioxide—a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.

Commissioner—the Commissioner of Conservation or any person to whom he has delegated authority in the matter concerned. For the purpose of these regulations, the commissioner is the delegated authority of the Secretary of Transportation.

Component—any part of a pipeline which may be subjected to pump pressure including, but not limited to, pipe, valves, elbows, tees, flanges, and closures.

Computation Pipeline Monitoring (CPM)—a software-based monitoring tool that alerts the pipeline dispatcher of a possible pipeline operating anomaly that may be indicative of a commodity release.

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

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

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

Corrosive Product—*corrosive material* as defined by CFR 173.136 Class 8—Definitions of this Chapter.

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

Flammable Product—*flammable liquid* as defined by CFR 173.120 Class 3—Definitions of this Chapter.

Gathering Line—a pipeline 8-5/8 in. (219.1 mm.) or less nominal outside diameter that transports petroleum from a production facility.

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

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

Hazardous Liquid—petroleum, petroleum products, anhydrous ammonia, and ethanol or other non- petroleum fuel, including biofuel, which is flammable, toxic, or would be harmful to the environment if released in significant quantities.

Highly Volatile Liquid or *HVL*—a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 40 psia (276 kPa) at 100°F (37.8°C).

In-Line Inspection (ILI)—inspection of a pipeline from the interior of the pipe using an in-line inspection tool. Also called intelligent or smart pigging.

In-Line Inspection Tool or Instrumented Internal Inspection Device—a device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside. Also known as intelligent or smart pig.

In-Plant Piping System—piping that is located on the grounds of a plant and used to transfer hazardous liquid or carbon dioxide between plant facilities or between plant facilities and a pipeline or other mode of transportation, not including any device and associated piping that are necessary to control pressure in the pipeline under §30406.B.

Interstate Pipeline—a pipeline or that part of a pipeline that is used in the transportation of hazardous liquids or carbon dioxide in interstate or foreign commerce.

Intrastate Pipeline—a pipeline or that part of a pipeline to which this Subpart applies that is not an interstate pipeline.

Line Section—a continuous run of pipe between adjacent pressure pump stations, between a pressure pump station and terminal or breakout tanks, between a pressure pump station and a block valve, or between adjacent block valves.

Low-Stress Pipeline—a hazardous liquid pipeline that is operated (based on MOP) in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe.

Maximum Operating Pressure (MOP)—the maximum pressure at which a pipeline or segment of a pipeline may be normally operated under this Subpart.

Nominal Wall Thickness—the wall thickness listed in the pipe specifications.

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

Operator—a person who owns or operates pipeline facilities.

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

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

Petroleum—crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas.

Petroleum Product—flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds.

Pipe or *Line Pipe*—a tube, usually cylindrical, through which a hazardous liquid or carbon dioxide flows from one point to another.

Pipeline or *Pipeline System*—all parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.

Pipeline Facility—new and existing pipe, rights-of-way and any equipment, facility, or building used in the transportation of hazardous liquids or carbon dioxide.

Production Facility—piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum or carbon dioxide, or associated storage or measurement. (To be a production facility under this definition, piping or equipment must be used in the process of extracting petroleum or carbon dioxide from the ground or from facilities where CO_2 is produced, and preparing it for transportation by pipeline. This includes piping between treatment plants which extract carbon dioxide, and facilities utilized for the injection of carbon dioxide for recovery operations.)

Rural Area—outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, or community development.

Significant Stress Corrosion Cracking—a stress corrosion cracking (SCC) cluster in which the deepest crack, in a series of interacting cracks, is greater than 10 percent of the wall thickness and the total interacting length of the cracks is equal to or greater than 75 percent of the critical length of a 50 percent through-wall flaw that would fail at a stress level of 110 percent of SMYS.

Specified Minimum Yield Strength—the minimum yield strength, expressed in pounds per square inch (p.s.i.) (kPa) gauge, prescribed by the specification under which the material is purchased from the manufacturer.

Stress Level—the level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

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

Surge Pressure—pressure produced by a change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.

Toxic Product—*poisonous material* as defined by CFR 173.132 Class 6, Division 6.1—Definitions of this Chapter.

Transportation of Hazardous Liquids—the gathering, transmission, or distribution of hazardous liquids by pipeline.

Unusually Sensitive Area (*USA*)—a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release, as identified under §30112.

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

Welding Operator—a person who operates machine or automatic welding equipment.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 18:861 (August 1992), LR 21:815 (August 1995), LR 27:1523 (September 2001), LR 28:83 (January 2002), LR 29:2805 (December 2003), LR 31:675 (March 2005), LR 33:467 (March 2007), LR 38:99 (January 2012), LR 44:1021 (June 2018), LR 46:1604 (November 2020).

§30107. Matter Incorporated by Reference in Whole or in Part [49 CFR 195.3]

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

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

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

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

c. Copies of standards incorporated by reference in this part can also be purchased from the respective standards-developing organization at the addresses provided in the centralized IBR section below.

Source and Name of Referenced Material	Approved for Title 33 Reference
B. American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, phone: 202-682-8000, http://api.org/.	
1. API Publication 2026, "Safe Access/Egress Involving Floating Roofs of Storage Tanks in Petroleum Service," 2nd edition, April 1998 (reaffirmed June 2006) (API Pub 2026).	§30405
2. API Recommended Practice 5L1, "Recommended Practice for Railroad Transportation of Line Pipe," 7th edition, September 2009, (API RP 5L1).	§30207.A
3. API Recommended Practice 5LT, "Recommended Practice for Truck Transportation of Line Pipe," First edition, March 12, 2012, (API RP 5LT).	§30207.C
4. API Recommended Practice 5LW, "Recommended Practice Transportation of Line Pipe on Barges and Marine Vessels," 3rd edition, September 2009, (API RP 5LW).	§30207.B
5. ANSI/API Recommended Practice 651, "Cathodic Protection of Aboveground Petroleum Storage Tanks," 3rd edition, January 2007, (ANSI/API RP 651).	§§30565.A; 30573.D
6. ANSI/API Recommended Practice 652, "Linings of Aboveground Petroleum Storage Tank Bottoms," 3rd edition, October 2005, (API RP 652).	§30207.B
7. API Recommended Practice 1130, "Computational Pipeline Monitoring for Liquids: Pipeline Segment," 3rd edition, September 2007, (API RP 1130).	§30207.B
8. API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," 1st edition, December 2003, (API RP 1162).	§§30440.A; 30440.B; 30440.C
9. API Recommended Practice 1165, "Recommended Practice for Pipeline SCADA Displays," First edition, January 2007, (API RP 1165).	§30446.C
10. API Recommended Practice 1168, "Pipeline Control Room Management," First edition, September 2008, (API RP 1168).	§§30446.C; 30446.F
11. API Recommended Practice 2003, "Protection against Ignitions Arising out of Static, Lightning, and Stray Currents," 7th edition, January 2008, (API RP 2003).	§30405.A
12. API Recommended Practice 2350, "Overfill Protection for Storage Tanks in Petroleum Facilities," 3rd edition, January 2005, (API RP 2350).	§30428.C
13. API Specification 5L, "Specification for Line Pipe," 45th edition, effective July 1, 2013, (ANSI/API Spec 5L).	§§30161.B; 30161.E

Source and Name of Referenced Material	Approved for Title 33 Reference
14. ANSI/API Specification 6D, "Specification for Pipeline Valves," 23rd edition, effective October 1, 2008, (including Errata 1 (June 2008), Errata 2 (November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), and Errata 6 (August 2011); Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012)); (ANSI/API Spec 6D).	§30173.D
15. API Specification 12F, "Specification for Shop Welded Tanks for Storage of Production Liquids," 12th edition, October 2008, effective April 1, 2009, (API Spec 12F).	§§30189.B; 30205.B; 30264.B; 30264.E; 30307.A; 30565; 30549.D
16. API Standard 510, "Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration," 9th edition, June 2006, (API Std 510).	§§30205.B; 30432.C
17. API Standard 620, "Design and Construction of Large, Welded, Low-Pressure Storage Tanks," 11th edition February 2008 (including addendum 1 (March 2009), addendum 2 (August 2010), and addendum 3 (March 2012)), (API Std 620).	§§30189.B; 30205.B; 30264.B; 30264.E; 30307.B; 30565; 30579.D
18. API Standard 650, "Welded Steel Tanks for Oil Storage," 11th edition, June 2007, effective February 1, 2012, (including addendum 1 (November 2008), addendum 2 (November 2009), addendum 3 (August 2011), and errata (October 2011)), (API Std 650).	§§30189.B; 30205.B; 30264.B; 30264.E; 30307.C; 30307.D; 30565; 30579.D
19. API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," 3rd edition, December 2001, (including addendum 1 (September 2003), addendum 2 (November 2005), addendum 3 (February 2008), and errata (April 2008)), (API Std 653).	§§30205.B; 30307.D; 30432.B
20. API Standard 1104, "Welding of Pipelines and Related Facilities," 20th edition, October 2005, (including errata/addendum (July 2007) and errata 2 (2008), (API Std 1104)).	§§30446.C; 30446.F
21. ANSI/API Standard 2000, "Venting Atmospheric and Low-pressure Storage Tanks," 6th edition, November 2009, (ANSI/API Std 2000).	§30264.E
22. API Standard 2510, "Design and Construction of LPG Installations," 8th edition, 2001, (API Std 2510).	§§30189.B; 30205.B; 30264.B; 30307.E; 30428.C; 30432.C
23. API Standard 1163, "In-Line Inspection Systems Qualification" Second edition, April 2013, (API Std 1163).	§30591
C. ASME International (ASME), Two Park Avenue, New York, NY 10016, 800-843-2763 (U.S/Canada), Web site: http://www.asme.org/.	
1. ASME/ANSI B16.9-2007, "Factory-Made Wrought Buttwelding Fittings," December 7, 2007, (ASME/ANSI B16.9).	§30175.A
2. ASME/ANSI B31G-1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ANSI B31G).	§§30452.H; 30587; 30588.C
3. ASME/ANSI B31.4-2006, "Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids" October 20, 2006, (ASME/ANSI B31.4).	§§30165.A; 30452.H
4. ASME/ANSI B31.8-2007, "Gas Transmission and Distribution Piping Systems," November 30, 2007, (ASME/ANSI B31.8).	§§30111.A; 30406.A
5. ASME Boiler & Pressure Vessel Code, Section VIII, Division 1, "Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1).	§§30181; 30307.E

Source and Name of Referenced Material	Approved for Title 33 Reference
6. ASME Boiler & Pressure Vessel Code, Section VIII, Division 2, "Alternate Rules, Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2).	§30307.E
7. ASME Boiler & Pressure Vessel Code, Section IX: "Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators," 2007 edition, July 1, 2007, (ASME BPVC, Section IX).	§30222.A
D. American Society for Nondestructive Testing, P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228. https://asnt.org.	
1. ANSI/ASNT ILI-PQ-2005(2010), "In-line Inspection Personnel Qualification and Certification" reapproved October 11, 2010, (ANSI/ ASNT ILI-PQ).	§30591
2. [Reserved]	
E. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 119428, phone: 610-832-9585, Web site: http://www.astm.org/.	
1. ASTM A53/A53M-10, "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless," approved October 1, 2010, (ASTM A53/A53M).	§30161.E
2. ASTM A106/A106M-10, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service," approved April 1, 2010, (ASTM A106/A106M).	§30161.E
3. ASTM A333/A333M-11, "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service," approved April 1, 2011, (ASTM A333/A333M	§30161.E
4. ASTM A381-96 (Reapproved 2005), "Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems," approved October 1, 2005, (ASTM A381).	§30161.E
5. ASTM A671/A671M-10, "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures," approved April 1, 2010, (ASTM A671/A671M	§30161.E
6. ASTM A672/A672M-09, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures," approved October 1, 2009, (ASTM A672/A672M	§30161.E
7. ASTM A691/A691M-09, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures," approved October 1, 2009, (ASTM A691).	§30161.E
F. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703-281-6613, Web site: http://www.mss-hq.org/.	
1. MSS SP-75-2008 Standard Practice, "Specification for High-Test, Wrought, Butt-Welding Fittings," 2008 edition, (MSS SP 75), IBR approved for §195.118(a).	§30175.A
2. [Reserved]	
G. NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084, phone: 281-228-6223 or 800-797-6223, Web site: http://www.nace.org/Publications/.	
1. NACE SP0169-2007, Standard Practice, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" reaffirmed March 15, 2007, (NACE SP0169).	§§30571; 30573
2. ANSI/NACE SP0502-2010, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology," June 24, 2010, (NACE SP0502).	§30588.B
3. ACE SP0102-2010, "Standard Practice, Inline Inspection of Pipelines" revised March 13, 2010, (NACE SP0102).	§§30177; 30591

Source and Name of Referenced Material	Approved for Title 33 Reference
4. NACE SP0204-2008, "Standard Practice, Stress Corrosion Cracking (SSC) Direct Assessment Methodology" reaffirmed September 18, 2008, (NACE SP0204).	§30588.C
H. National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, MA 02169, phone: 617-984-7275, Web site: http://www.nfpa.org/.	
1. NFPA-30 (2012), "Flammable and Combustible Liquids Code," including Errata 30-12-1 (9/27/11), and Errata 30-12-2 (11/14/11), 2012 edition, copyright 2011, (NFPA-30).	§30264.B
2. [Reserved]	
I. Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713-630-0505, toll free: 866-866-6766, Web site: http://www.ttoolboxes.com/.	
1. AGA Pipeline Research Committee, Project PR-3-805 "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," December 22, 1989, (PR-3-805 (RSTRING)). IBR approved for §§195.452(h); 195.587; and 195.588(c).	§§30587; 30588.C
2. [Reserved]	

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§30109. Compatibility Necessary for Transportation of Hazardous Liquids or Carbon Dioxide [49 CFR 195.4]

A. No person may transport any hazardous liquid or carbon dioxide unless the hazardous liquid or carbon dioxide is chemically compatible with both the pipeline, including all components, and any other commodity that it may come into contact with while in the pipeline. [49 CFR 195.4]

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§30111. Conversion to Service Subject to This Subpart [49 CFR 195.5]

A. A steel pipeline previously used in service not subject to this Subpart qualifies for use under this Subpart if the operator prepares and follows a written procedure to accomplish the following. [49 CFR 195.5(a)]

1. The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in satisfactory condition for safe operation. If one or more of the variables necessary to verify the design pressure under §30161 or to perform the testing under Paragraph A.4 of this Section is unknown, the design pressure may be verified and the maximum operating pressure determined by: [49 CFR 195.5(a)(1)]

a. testing the pipeline in accordance with ASME/ANSI B31.8 (incorporated by reference, see §507), Appendix N, to produce a stress equal to the yield strength; and [49 CFR 195.5(a)(1)(i)]

b. applying to not more than 80 percent of the first pressure that produces a yielding, the design factor F in §30161.A and the appropriate factors in §30161.E. [49 CFR 195.5(a)(1)(ii)]

2. The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline. [49 CFR 195.5(a)(2)]

3. All known unsafe defects and conditions must be corrected in accordance with this Subpart. [49 CFR 195.5(a)(3)]

4. The pipeline must be tested in accordance with Chapter 303 to substantiate the maximum operating pressure permitted by §30406. [49 CFR 195.5(a)(4)]

B. A pipeline which qualifies for use under this Section need not comply with the corrosion control requirements of this Subchapter B of Chapter 305 until 12 months after it is placed in service, notwithstanding any previous deadlines for compliance. [49 CFR 195.5(b)]

C. Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of §30111.A. [49 CFR 195.5(c)]

D. An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by §30146. [49 CFR 195.5(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 21:816 (August 1995), LR 29:2808 (December 2003), LR 44:1023 (June 2018).

§30112. Unusually Sensitive Areas (USAs) [49 CFR 195.6]

A. As used in this Subpart, a USA means a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release.

1. A USA drinking water resource is:

a. the water intake for a Community Water System (CWS) or a Non-Transient Non-Community Water System (NTNCWS) that obtains its water supply primarily from a surface water source and does not have an adequate alternative drinking water source;

b. the Source Water Protection Area (SWPA) for a CWS or a NTNCWS that obtains its water supply from a Class I or Class IIA aquifer and does not have an adequate alternative drinking water source. Where a state has not yet identified the SWPA, the Wellhead Protection Area (WHPA) will be used until the state has identified the SWPA; or

c. the sole source aquifer recharge area where the sole source aquifer is a karst aquifer in nature.

2. An USA ecological resource is:

a. an area containing a critically imperiled species or ecological community;

b. a multi-species assemblage area;

c. a migratory waterbird concentration area;

d. an area containing an imperiled species, threatened or endangered species, depleted marine mammal species, or an imperiled ecological community where the species or community is aquatic, aquatic dependent, or terrestrial with a limited range; or

e. an area containing an imperiled species, threatened or endangered species, depleted marine mammal species, or an imperiled ecological community where the species or community occurrence is considered to be one of the most viable, highest quality, or in the best condition as identified by an element occurrence ranking (EORANK) of A (excellent quality) or B (good quality).

3. As used in this Subpart:

Adequate Alternative Drinking Water Source—a source of water that currently exists, can be used almost immediately with a minimal amount of effort and cost, involves no decline in water quality, and will meet the consumptive, hygiene, and fire fighting requirements of the existing population of impacted customers for at least one month for a surface water source of water and at least six months for a groundwater source.

Aquatic or *Aquatic Dependent Species* or *Community*—a species or community that primarily occurs in aquatic, marine, or wetland habitats, as well as species that may use terrestrial habitats during all or some portion of their life cycle, but that are still closely associated with or dependent upon aquatic, marine, or wetland habitats for some critical component or portion of their life-history (i.e., reproduction, rearing and development, feeding, etc).

Class I Aquifer—an aquifer that is surficial or shallow, permeable, and is highly vulnerable to contamination. Class I aquifers include:

i. *Unconsolidated Aquifers* (*Class Ia*)—that consist or surficial, unconsolidated, and permeable, alluvial, terrace, outwash, beach, dune, and other similar deposits. These aquifers generally contain layers of sand and gravel that, commonly, are interbedded to some degree with silt and clay. Not all Class Ia aquifers are important water-bearing units, but they are likely to be both permeable and vulnerable. The only natural protection of these aquifers is the thickness of the unsaturated zone and the presence of fine-grained material;

ii. *Soluble and Fractured Bedrock Aquifers* (*Class Ib*)—lithologies in this class include limestone, dolomite, and locally, evaporitic units that contain documented karst features or solution channels, regardless of size. Generally, these aquifers have a wide range of permeability. Also included in this class are sedimentary strata, and metamorphic and igneous (intrusive and extrusive) rocks that are significantly faulted, fractured, or jointed. In all cases groundwater movement is largely controlled by secondary openings. Well yields range widely, but the important feature is the potential for rapid vertical and lateral groundwater movement along preferred pathways, which result in a high degree of vulnerability;

iii. *Semiconsolidated Aquifers* (*Class Ic*)—that generally contain poorly to moderately indurated sand and gravel that is interbedded with clay and silt. This group is intermediate to the unconsolidated and consolidated end members. These systems are common in the Tertiary age rocks that are exposed throughout the Gulf and Atlantic coastal states. Semiconsolidated conditions also arise from the presence of intercalated clay and caliche within primarily unconsolidated to poorly consolidated units, such as occurs in parts of the High Plains Aquifer; or

iv. *Covered Aquifers* (*Class Id*)—that are any Class I aquifer overlain by less than 50 feet of low permeability, unconsolidated material, such as glacial till, lacustrian, and loess deposits.

Class IIa Aquifer—Higher Yield Bedrock Aquifer that is consolidated and is moderately vulnerable to contamination. These aquifers generally consist of fairly permeable sandstone or conglomerate that contain lesser amounts of interbedded fine grained clastics (shale, siltstone, mudstone) and occasionally carbonate units. In general, well yields must exceed 50 gallons per minute to be included in this class. Local fracturing may contribute to the dominant primary porosity and permeability of these systems.

Community Water System (*CWS*)—a public water system that serves at least 15 service connections used by year-round residents of the area or regularly serves at least 25 year-round residents.

Critically Imperiled Species or Ecological Community (*Habitat*)—an animal or plant species or an *ecological community* of extreme rarity, based on The Nature Conservancy's Global Conservation Status Rank. There are generally five or fewer occurrences, or very few remaining individuals (less than 1,000) or acres (less than 2,000). These species and ecological communities are extremely vulnerable to extinction due to some natural or man-made factor.

Depleted Marine Mammal Species—a species that has been identified and is protected under the Marine Mammal Protection Act of 1972, as amended (MMPA) (16 U.S.C. 1361 et seq.). The term *depleted* refers to marine mammal species that are listed as threatened or endangered, or are below their optimum sustainable populations (16 U.S.C. 1362). The term *marine mammal* means “any mammal which is morphologically adapted to the marine environment (including sea otters and members of the orders Sirenia, Pinnipedia, and Cetacea), or primarily inhabits the marine environment (such as the polar bear)” (16 U.S.C. 1362). The order Sirenia includes manatees, the order Pinnipedia includes seals, sea lions, and walruses, and the order Cetacea includes dolphins, porpoises, and whales.

Ecological Community—an interacting assemblage of plants and animals that recur under similar environmental conditions across the landscape.

Element Occurrence Rank (EORANK)—the condition or viability of a species or ecological community occurrence, based on a population’s size, condition, and landscape context. EORANKs are assigned by the Natural Heritage Programs. An EORANK of A means an excellent quality and an EORANK of B means good quality.

Imperiled Species or Ecological Community (*Habitat*)—a rare *species* or *ecological community*, based on The Nature Conservancy’s Global Conservation Status Rank. There are generally six to 20 occurrences, or few remaining individuals (1,000 to 3,000) or acres (2,000 to 10,000). These species and ecological communities are vulnerable to extinction due to some natural or man-made factor.

Karst Aquifer—an aquifer that is composed of limestone or dolomite where the porosity is derived from connected solution cavities. Karst aquifers are often cavernous with high rates of flow.

Migratory Waterbird Concentration Area—a designated Ramsar site or a Western Hemisphere Shorebird Reserve Network site.

Multi Species Assemblage Area—an area where three or more different critically imperiled or imperiled species or ecological communities, threatened or endangered species, depleted marine mammals, or migratory water bird concentrations co-occur.

Non-Transient Non-Community Water System (*NTNCWS*)—a public water system that regularly serves at least 25 of the same persons over six months per year. Examples of these systems include schools, factories, and hospitals that have their own water supplies.

Public Water System (*PWS*)—a system that provides the public water for human consumption through pipes or other constructed conveyances, if such systems has at least 15 service connections or regularly serves an average of at least 25 individuals daily at least 60 days out of the year. These systems include the sources of the water supplies, i.e., surface or ground. PWS can be community, non-transient non-community, or transient non-community systems.

Ramsar Site—a site that has been designated under the Convention on Wetlands of International Importance Especially as Waterfowl Habitat Program. Ramsar sites are globally critical wetland areas that support migratory waterfowl. These include wetland areas that regularly support 20,000 waterfowl; wetland areas that regularly support substantial numbers of individuals from particular groups of waterfowl, indicative of wetland values, productivity, or diversity; and wetland areas that regularly support 1 percent of the individuals in a population of one species or subspecies of waterfowl.

Sole Source Aquifer (*SSA*)—an area designed by the U.S. Environmental Protection Agency under the Sole Source Aquifer Program as the “sole or principal” source of drinking water for an area. Such designations are made if the aquifer’s groundwater supplies 50 percent or more of the drinking water for an area, and if that aquifer were to become contaminated, it would pose a public health hazard. A sole source aquifer that is karst in nature is one composed of limestone where the porosity is derived from connected solution cavities. They are often cavernous, with high rates of flow.

Source Water Protection Area (*SWPA*)—that the area delineated by the state for a public water supply system (PWS) or including numerous PWSs, whether the source is groundwater or surface water or both, as part of the state source water assessment program (SWAP) approved by EPA under §1453 of the Safe Drinking Water Act.

Species—species, subspecies, population stocks, or distinct vertebrate populations.

Terrestrial Ecological Community with a Limited Range—a non-aquatic or non-aquatic dependent ecological community that covers less than 5 acres.

Terrestrial Species with a Limited Range—a non-aquatic or non-aquatic dependent animal or plant species that has a range of no more than 5 acres.

Threatened and Endangered Species (T&E)—an animal or plant species that has been listed and is protected under the Endangered Species Act of 1973, as amended (ESA 73)(16 U.S.C. 1531 et seq.).

i. *Endangered Species*—any species which is in danger of extinction throughout all or a significant portion of its range (16 U.S.C. 1532).

ii. *Threatened Species*—any species which is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range (16 U.S.C. 1532).

Transient Non-Community Water System (TNCWS)—a public water system that does not regularly serve at least 25 of the same persons over six months per year. This type of water system serves a transient population found at rest stops, campgrounds, restaurants, and parks with their own source of water.

Wellhead Protection Area (*WHPA*)—the surface and subsurface area surrounding a well or well field that supplies a public water system through which contaminants are likely to pass and eventually reach the water well or well field.

Western Hemisphere Shorebird Reserve Network (WHSRN) Site—an area that contains migratory shorebirds concentrations and has been designated as a hemispheric reserve, international reserve, regional reserve, or endangered species reserve. Hemispheric reserves host at least 500,000 shorebirds annually or 30 percent of a species flyaway population. International reserves host 100,000 shorebirds annually or 15 percent of a species flyaway population. Regional reserves host 20,000 shorebirds annually or 5 percent of a species flyaway population. Endangered species reserves are critical to the survival of endangered species and no minimum number of birds is required.

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HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 28:83 (January 2002), amended LR 29:2808 (December 2003), repromulgated LR 30:257 (February 2004).

§30114. Transportation of Hazardous Liquid or Carbon Dioxide in Pipelines Constructed with Other than Steel Pipe [49 CFR 195.8]

A. No person may transport any hazardous liquid or carbon dioxide through a pipe that is constructed after October 1, 1970, for hazardous liquids or after July 12, 1991, for carbon dioxide of material other than steel unless the person has notified the commissioner and administrator in writing at least 90 days before the transportation is to begin. The notice must state whether carbon dioxide or a hazardous liquid is to be transported and the chemical name, common name, properties and characteristics of the hazardous liquid to be transported and the material used in construction of the pipeline. If the commissioner and administrator determine that the transportation of the hazardous liquid or carbon dioxide in the manner proposed would be unduly hazardous, he will, within 90 days after receipt of the notice, order the person that gave the notice, in writing, not to transport the hazardous liquid or carbon dioxide in the proposed manner until further notice. [49 CFR 195.8]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2810 (December 2003).

§30116. Responsibility of Operator for Compliance with This Subpart [49 CFR 195.10]

A. An operator may make arrangements with another person for the performance of any action required by this Subpart. However, the operator is not thereby relieved from the responsibility for compliance with any requirement of this Subpart.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2810 (December 2003).

§30117. What is a regulated rural gathering line and what requirements apply? [49 CFR 195.11]

A. Each operator of a regulated rural gathering line, as defined in Paragraph 1 of this section, must comply with the safety requirements described in Paragraph 2 of this Section. [49 CFR 195.11]

1. Definition. As used in this section, a *regulated rural gathering line* means an onshore gathering line in a rural area that meets all of the following criteria— [49 CFR 195.11(a)]

a. has a nominal diameter from 6⅝ inches (168 mm) to 8⅝ inches (219.1 mm); [49 CFR 195.11(a)(1)]

b. is located in or within one-quarter mile (.40 km) of an unusually sensitive area as defined in §30112; and [49 CFR 195.11(a)(2)]

c. operates at a maximum pressure established under §30406 corresponding to: [49 CFR 195.11(a)(3)]

i. A stress level greater than 20 percent of the specified minimum yield strength of the line pipe; or [49 CFR 195.11(a)(3)(i)]

ii. if the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure of more than 125 psi (861 kPa) gage. [49 CFR 195.11(a)(3)(ii)]

2. Safety Requirements. Each operator must prepare, follow, and maintain written procedures to carry out the requirements of this section. Except for the requirements in Subparagraphs A.2.b, A.2.c, A.2.i and A.2.j of this section, the safety requirements apply to all materials of construction. [49 CFR 195.11(b)]

a. Identify all segments of pipeline meeting the criteria in Paragraph 1 of this section before April 3, 2009. [49 CFR 195.11(b)(1)]

b. For steel pipelines constructed, replaced, relocated, or otherwise changed after July 3, 2009, design, install, construct, initially inspect, and initially test the pipeline in compliance with this Subpart, unless the pipeline is converted under §30111. [49 CFR 195.11(b)(2)]

c. For non-steel pipelines constructed after July 3, 2009, notify the Administrator according to §30114. [49 CFR 195.11(b)(3)]

d. Beginning no later than January 3, 2009, comply with the reporting requirements in Subchapter B of Chapter 301 this Subpart. [49 CFR 195.11(b)(4)]

e. Establish the maximum operating pressure of the pipeline according to §30406 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009. [49 CFR 195.11(b)(5)]

f. Install line markers according to §30410 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009. Continue to maintain line markers in compliance with §30410. [49 CFR 195.11(b)(6)]

g. Establish a continuing public education program in compliance with §30440 before transportation begins, or if the pipeline exists on July 3, 2008, before January 3, 2010. Continue to carry out such program in compliance with §30440. [49 CFR 195.11(b)(7)]

h. Establish a damage prevention program in compliance with §30442 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009. Continue to carry out such program in compliance with §30442. [49 CFR 195.11(b)(8)]

i. For steel pipelines, comply with Subchapter B of Chapter 305 of this Subpart, except corrosion control is not required for pipelines existing on July 3, 2008 before July 3, 2011. [49 CFR 195.11(b)(9)]

j. For steel pipelines, establish and follow a comprehensive and effective program to continuously identify operating conditions that could contribute to internal corrosion. The program must include measures to prevent and mitigate internal corrosion, such as cleaning the pipeline and using inhibitors. This program must be established before transportation begins or if the pipeline exists on July 3, 2008, before July 3, 2009. [49 CFR 195.11(b)(10)]

k. To comply with the Operator Qualification program requirements in Subchapter A of Chapter 305 of this Subpart, have a written description of the processes used to carry out the requirements in §30505 to determine the qualification of persons performing operations and maintenance tasks. These processes must be established before transportation begins or if the pipeline exists on July 3, 2008, before July 3, 2009. [49 CFR 195.11(b)(11)]

3. New Unusually Sensitive Areas. If, after July 3, 2008, a new unusually sensitive area is identified and a segment of pipeline becomes regulated as a result, except for the requirements of Subparagraphs A.2.i and A.2.j of this section, the operator must implement the requirements in Subparagraphs A.2.b through A.2.k of this section for the affected segment within 6 months of identification. For steel pipelines, comply with the deadlines in Subparagraph A.2.i and A.2.j. [49 CFR 195.11(c)]

4. Record Retention. An operator must maintain records demonstrating compliance with each requirement according to the following schedule. [49 CFR 195.11(d)]

a. An operator must maintain the segment identification records required in Subparagraph A.2.a of this section and the records required to comply with A.2.j of this section, for the life of the pipe. [49 CFR 195.11(d)(1)]

b. An operator must maintain the records necessary to demonstrate compliance with each requirement in Subparagraphs A.2.b through A.2.i, and A.2.k of this section according to the record retention requirements of the referenced section or Chapter. [49 CFR 195.11(d)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 35:2793 (December 2009).

§30118. What requirements apply to low-stress pipelines in rural areas? [49 CFR 195.12]

A. General. This Section sets forth the requirements for each category of lowstress pipeline in a rural area set forth in Subsection B of this Section. This Section does not apply to a rural lowstress pipeline regulated under this Subpart as a low-stress pipeline that crosses a waterway currently used for commercial navigation; these pipelines are regulated pursuant to §30103.A.2. [49 CFR 195.12(a)]

B. Categories. An operator of a rural low-stress pipeline must meet the applicable requirements and compliance deadlines for the category of pipeline set forth in Subsection C of this Section. For purposes of this Section, a rural low-stress pipeline is a Category 1, 2, or 3 pipeline based on the following criteria. [49 CFR 195.12(b)]

1. A Category 1 rural low-stress pipeline: [49 CFR 195.12(b)(1)]

a. has a nominal diameter of 85⁄8 inches (219.1 mm) or more; [49 CFR 195.12(b)(1)(i)]

b. is located in or within one-half mile (.80 km) of an unusually sensitive area (USA) as defined in §30112; and [49 CFR 195.12(b)(1)(ii)]

c. operates at a maximum pressure established under §30406 corresponding to: [49 CFR 195.12(b)(1)(iii)]

i. a stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or [49 CFR 195.12(b)(1)(iii)(A)]

ii. if the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gage. [49 CFR 195.12(b)(1)(iii)(B)]

2. A Category 2 rural pipeline: [49 CFR 195.12(b)(2)]

a. has a nominal diameter of less than 85⁄8 inches (219.1mm); [49 CFR 195.12(b)(2)(i)]

b. is located in or within one-half mile (.80 km) of an unusually sensitive area (USA) as defined in §30112; and [49 CFR 195.12(b)(2)(ii)]

c. operates at a maximum pressure established under §30406 corresponding to: [49 CFR 195.12(b)(2)(iii)]

i. a stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or [49 CFR 195.12(b)(2)(iii)(A)]

ii. if the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gage. [49 CFR 195.12(b)(2)(iii)(B)]

3. A Category 3 rural low-stress pipeline: [49 CFR 195.12(b)(3)]

a. has a nominal diameter of any size and is not located in or within one-half mile (.80 km) of an unusually sensitive area (USA) as defined in §30112; and [49 CFR 195.12(b)(3)(i)]

b. operates at a maximum pressure established under §30406 corresponding to a stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or [49 CFR 195.12(b)(3)(ii)]

c. if the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gage. [49 CFR 195.12(b)(3)(iii)]

C. Applicable Requirements and Deadlines for Compliance. An operator must comply with the following compliance dates depending on the category of pipeline determined by the criteria in Subsection B. [49 CFR 195.12(c)]

1. An operator of a Category 1 pipeline must: [49 CFR 195.12(c)(1)]

a. identify all segments of pipeline meeting the criteria in Paragraph B.1 of this Section before April 3, 2009; [49 CFR 195.12(c)(1)(i)]

b. beginning no later than January 3, 2009, comply with the reporting requirements of Subchapter B of Chapter 301. for the identified segments; [49 CFR 195.12(c)(1)(ii)]

c. IM requirements; [49 CFR 195.12(c)(1)(iii)]

i. establish a written program that complies with §30452 before July 3, 2009, to assure the integrity of the pipeline segments. Continue to carry out such program in compliance with §30452; [49 CFR 195.12(c)(1)(iii)(A)]

ii. an operator may conduct a determination per §30452.A in lieu of the one-half mile buffer; [49 CFR 195.12(c)(1)(iii)(B)]

iii. complete the baseline assessment of all segments in accordance with §30452.C before July 3, 2015, and complete at least 50-percent of the assessments, beginning with the highest risk pipe, before January 3, 2012; [49 CFR 195.12(c)(1)(iii)(C)]

d. comply with all other safety requirements of this Subpart, except Subchapter B of Chapter 305., before July 3, 2009. Comply with the requirements of Subchapter B of Chapter 305 before July 3, 2011. [49 CFR 195.12(c)(1)(d)]

2. An operator of a Category 2 pipeline must: [49 CFR 195.12(c)(2)]

a. identify all segments of pipeline meeting the criteria in Paragraph B.2 of this Section before July 1, 2012. [49 CFR 195.12(c)(2)(i)]

b. beginning no later than January 3, 2009, comply with the reporting requirements of Subchapter B of Chapter 301. for the identified segments; [49 CFR 195.12(c)(2)(ii)]

c. IM; [49 CFR 195.12(c)(2)(iii)]

i. establish a written IM program that complies with §30452 before October 1, 2012 to assure the integrity of the pipeline segments. Continue to carry out such program in compliance with §30452; [49 CFR 195.12(c)(2)(iii)(A)]

ii. an operator may conduct a determination per §30452.A in lieu of the one-half mile buffer; [49 CFR 195.12(c)(2)(iii)(B)]

iii. complete the baseline assessment of all segments in accordance with §30452.C before October 1, 2016 and complete at least 50-percent of the assessments, beginning with the highest risk pipe, before April 1, 2014; [49 CFR 195.12(c)(2)(iii)(C)]

d. comply with all other safety requirements of this Subpart, except Subchapter B of Chapter 305., before October 1, 2012. Comply with Subchapter B of Chapter 305. before October 1, 2014. [49 CFR 195.12(c)(2)(iv)]

3. An operator of a Category 3 pipeline must: [49 CFR 195.12(c)(3)]

a. identify all segments of pipeline meeting the criteria in Paragraph B.3 of this Section before July 1, 2012; [49 CFR 195.12(c)(3)(i)]

b. beginning no later than January 3, 2009, comply with the reporting requirements of Subchapter B of Chapter 301. for the identified segments; [49 CFR 195.12(c)(3)(ii)]

c. comply with all safety requirements of this Subpart, except the requirements in §30452, Subchapter B of Chapter 301, and the requirements in Subchapter B of Chapter 305, before October 1, 2012. Comply with Subchapter B of Chapter 305 before October 1, 2014. [49 CFR 195.12(c)(3)(iii)]

D. Economic Compliance Burden [49 CFR 195.12(d)]

1. An operator may notify PHMSA in accordance with §30452.M of a situation meeting the following criteria: [49 CFR 195.12(d)(1)]

a. the pipeline is a Category 1 rural low-stress pipeline; [49 CFR 195.12(d)(1)(i)]

b. the pipeline carries crude oil from a production facility; [49 CFR 195.12(d)(1)(ii)]

c. the pipeline, when in operation, operates at a flow rate less than or equal to 14,000 barrels per day; and [49 CFR 195.12(d)(1)(iii)]

d. the operator determines it would abandon or shut-down the pipeline as a result of the economic burden to comply with the assessment requirements in §§30452.D or 30452.J. [49 CFR 195.12(d)(1)(iv)]

2. A notification submitted under this provision must include, at minimum, the following information about the pipeline: Its operating, maintenance and leak history; the estimated cost to comply with the integrity assessment requirements (with a brief description of the basis for the estimate); the estimated amount of production from affected wells per year, whether wells will be shut in or alternate transportation used, and if alternate transportation will be used, the estimated cost to do so. [49 CFR 195.12(d)(2)]

3. When an operator notifies PHMSA in accordance with Paragraph D.1 of this Section, PHMSA will stay compliance with §§30452.D and 30452.J.3 until it has

completed an analysis of the notification. PHMSA will consult the Department of Energy (DOE), as appropriate, to help analyze the potential energy impact of loss of the pipeline. Based on the analysis, PHMSA may grant the operator a special permit to allow continued operation of the pipeline subject to alternative safety requirements. [49 CFR 195.12(d)(3)]

E. Changes in unusually sensitive areas. [49 CFR 195.12(e)]

1. If, after June 3, 2008, for Category 1 rural low-stress pipelines or October 1, 2011 for Category 2 rural low-stress pipelines, an operator identifies a new USA that causes a segment of pipeline to meet the criteria in Subsection B of this Section as a Category 1 or Category 2 rural low-stress pipeline, the operator must: [49 CFR 195.12(e)(1)]

a. comply with the IM program requirement in Clause C.1.c.i or C.2.c.i of this Section, as appropriate, within 12 months following the date the area is identified regardless of the prior categorization of the pipeline; and [49 CFR 195.12(e)(1)(i)]

b. complete the baseline assessment required by clause C.1.c.iii or C.2.c.iii of this Section, as appropriate, according to the schedule in §39452.D.3. [49 CFR 195.12(e)(1)(ii)]

2. If a change to the boundaries of a USA causes a Category 1 or Category 2 pipeline segment to no longer be within one-half mile of a USA, an operator must continue to comply with Subparagraph C.1.c or Subparagraph C.2.c of this Section, as applicable, with respect to that segment unless the operator determines that a release from the pipeline could not affect the USA. [49 CFR 195.12(e)(2)]

F. Record Retention. An operator must maintain records demonstrating compliance with each requirement applicable to the category of pipeline according to the following schedule. [49 CFR 195.12(f)]

1. An operator must maintain the segment identification records required in Subparagraph C.1.a, C.2.a or C.3.a of this Section for the life of the pipe. [49 CFR 195.12(f)(1)]

2. Except for the segment identification records, an operator must maintain the records necessary to demonstrate compliance with each applicable requirement set forth in Subsection C of this Section according to the record retention requirements of the referenced Section, Subpart or Subchapter.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 35:2794 (December 2009), amended LR 38:101 (January 2012).

§30119. What requirements apply to pipelines transporting hazardous liquids by gravity? [49 CFR 195.13]

A. Scope. Pipelines transporting hazardous liquids by gravity must comply with the reporting requirements of Subchapter B of this Subpart. [49 CFR 195.13(a)]

B. Implementation Period [49 CFR 195.13(b)]

1. Annual Reporting. Comply with the annual reporting requirements in Subchapter B of this Subpart by March 31, 2021. [49 CFR 195.13(b)(1)]

2. Accident and Safety-Related Reporting. Comply with the accident and safety-related condition reporting requirements in Subchapter B of this Subpart by January 1, 2021. [49 CFR 195.13(b)(2)]

C. Exceptions [49 CFR 195.13(c)]

1. This Section does not apply to the transportation of a hazardous liquid in a gravity line that meets the definition of a low-stress pipeline, travels no farther than one mile from a facility boundary, and does not cross any waterways used for commercial navigation. [49 CFR 195.13(c)(1)]

2. The reporting requirements in §§30127, 30143, and 30147 do not apply to the transportation of a hazardous liquid in a gravity line. [49 CFR 195.13(c)(2)]

3. The drug and alcohol testing requirements in Title 43:XIII.6101-6545 do not apply to the transportation of a hazardous liquid in a gravity line. [49 CFR 195.13(c)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 46:1605 (November 2020).

§30121. What requirements apply to reporting-regulated-only gathering lines? [49 CFR 195.15]

A. Scope. Gathering lines that do not otherwise meet the definition of a regulated rural gathering line in §30117 and any gathering line not already covered under §30103.A.1, 2, 3 or 4 must comply with the reporting requirements of Subchapter B of this Chapter. [49 CFR 195.15(a)]

B. Implementation Period [49 CFR 195.15(b)].

1. Annual Reporting. Operators must comply with the annual reporting requirements in subpart B of this part by March 31, 2021. [49 CFR 195.15(b)(1)]

2. Accident and Safety-Related Reporting. Operators must comply with the accident and safety-related condition reporting requirements in Subchapter B of this Subpart by January 1, 2021. [49 CFR 195.15(b)(2)]

C. Exceptions [49 CFR 195.15(c)]

1. This Section does not apply to those gathering lines that are otherwise excepted under §30103.B.3, 7, 8, 9, or 10. [49 CFR 195.15(c)(1)]

2. The reporting requirements in §§30127, 30143, and 30147 do not apply to the transportation of a hazardous liquid in a gathering line that is specified in Subsection A of this Section. [49 CFR 195.15(c)(2)]

3. The drug and alcohol testing requirements in Title 43:XIII.6101-6545 do not apply to the transportation of a hazardous liquid in a gathering line that is specified in Subsection A of this Section. [49 CFR 195.15(c)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 46:1605 (November 2020).

Subchapter B. Reporting Accidents and Safety-Related Conditions [Subpart B]

§30123. Scope [49 CFR 195.48]

A. This Subchapter prescribes requirements for periodic reporting and for reporting of accidents and safety-related conditions. This Subchapter applies to all pipelines subject to this Subpart. An operator of a Category 3 rural low-stress pipeline meeting the criteria in §30118 is not required to complete those parts of the hazardous liquid annual report form PHMSA F 7000-1.1 associated with IM or high consequence areas. [49CFR 195.48]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 35:2795 (December 2009), amended LR 38:103 (January 2012).

§30124. Annual Report [49 CFR 195.49]

A. Each operator must annually complete and submit DOT Form PHMSA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. An operator must submit the annual report by June 15 each year, except that for the 2010 reporting year the report must be submitted by August 15, 2011. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, carbon dioxide pipelines, and fuel grade ethanol pipelines. For each state a pipeline traverses, an operator must separately complete those sections on the form requiring information to be reported for each state. [49 CFR 195.49]

B. For intrastate facilities subject to the jurisdiction of the Office of Conservation, a copy of the annual report must be sent to the Commissioner of Conservation, Office of Conservation, Pipeline Safety Section, P.O. Box 94275 Baton Rouge, LA 70804-9275.

1. Annual report information must only include data for intrastate facilities subject to the jurisdiction of the Office of Conservation.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 38:103 (January 2012).

§30125. Reporting Accidents [49 CFR 195.50]

A. An accident report is required for each failure in a pipeline system subject to this Subpart in which there is a release of the hazardous liquid or carbon dioxide transported resulting in any of the following: [49 CFR 195.50]

1. explosion or fire not intentionally set by the operator; [49 CFR 195.50(a)]

2. release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is: [49 CFR 195.50(b)]

a. not otherwise reportable under this Section; [49 CFR 195.50(b)(1)]

b. not one described in §30127(A)(4); [49 CFR 195.50(b)(2)]

c. confined to company property or pipeline right-of-way; and [49 CFR 195.50(b)(3)]

d. cleaned up promptly; [49 CFR 195.50(b)(4)]

3. death of any person; [49 CFR 195.50(c)]

4. personal injury necessitating hospitalization; [49 CFR 195.50(d)]

5. estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000. [49 CFR 195.50(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 18:863 (August 1992), LR 21:816 (August 1995), LR 27:1524 (September 2001), LR 29:2811 (December 2003).

§30127. Telephonic Notice of Certain Accidents [49 CFR 195.52]

A. Notice Requirements. At the earliest practicable moment within one hour following discovery, of a release of the hazardous liquid or carbon dioxide transported resulting in an event described in §30125, but no later than one hour after confirmed discovery, the operator of the system shall give notice, in accordance with §30127.B of any failure that: [49 CFR 195.52(a)]

1. caused a death or a personal injury requiring hospitalization; [49 CFR 195.52(a)(1)]

2. resulted in either a fire or explosion not intentionally set by the operator; [49 CFR 195.52(a)(2)]

3. caused estimated property damage, including cost of clean-up and recovery, value of lost product, and damage

to the property of the operator or others, or both, exceeding $50,000; [49 CFR 195.52(a)(3)]

4. resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or [49 CFR 195.52(a)(4)]

5. in the judgment of the operator was significant even though it did not meet the criteria of any other paragraph of this Section. [49 CFR 195.52(a)(5)]

B. Information Required. Each notice required by Subsection A of this Section must be made to the National Response Center either by telephone to (800) 424-8802 (in Washington, DC, (202) 267-2675) or electronically at http://www.nrc.uscg.mil and by telephone to the State of Louisiana to (225) 342-5505 and must include the following information: [49 CFR 195.52(b)

1. name, address and identification number of the operator; [49 CFR 195.52(b)(1)]

2. name and telephone number of the reporter; [49 CFR 195.52(b)(2)]

3. the location of the failure; [49 CFR 195.52(b)(3)]

4. the time of the failure; [49 CFR 195.52(b)(4)]

5. the fatalities and personal injuries if any; [49 CFR 195.52(b)(5)]

6. initial estimate of amount of product released in accordance with Subsection C of this Section; [49 CFR 195.52(b)(6)]

7. all other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages. [49 CFR 195.52(b)(7)]

C. Calculation. A pipeline operator must have a written procedure to calculate and provide a reasonable initial estimate of the amount of released product. [49 CFR 195.52(c)]

D. New Information. Within 48 hours after the confirmed discovery of an accident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in Subsection B of this Section with a revised estimate of the amount of product released, location of the failure, time of the failure, a revised estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the accident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report. [49 CFR 195.52(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 18:863 (August 1992), LR 20:440 (April 1994), LR 21:816 (August 1995), LR 29:2811 (December 2003), LR 35:2795 (December 2009), LR 38:103 (January 2012), LR 44:1023 (June 2018).

§30131. Accident Reports [49 CFR 195.54]

A. Each operator that experiences an accident that is required to be reported under §30125 must, as soon as practicable, but not later than 30 days after discovery of the accident, file an accident report on DOT Form 7000-1. For intrastate facilities subject to the jurisdiction of the Office of Conservation, a copy of the accident report must be sent concurrently to the Commissioner of Conservation, Office of Conservation, Pipeline Safety Section, P.O. Box 94275 Baton Rouge, LA 70804-9275. [49 CFR 195.54(a)]

B. Whenever an operator receives any changes in the information reported or additions to the original report on DOT Form 7000-1, it shall file a supplemental report within 30 days. For intrastate facilities subject to the jurisdiction of the Office of Conservation, a copy of the supplemental report must be sent concurrently to the Commissioner of Conservation, Office of Conservation, Pipeline Safety Section, P.O. Box 94275 Baton Rouge, LA 70804-9275. [49 CFR 195.54(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), LR 20:440 (April 1994), LR 29:2811 (December 2003), amended LR 38:103 (January 2012).

§30133. Reporting Safety-Related Conditions [49 CFR 195.55]

A. Except as provided in §30133.B, each operator shall report in accordance with §30135 the existence of any of the following safety-related conditions involving pipelines in service: [49 CFR 195.55(a)]

1. general corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure, and localized corrosion pitting to a degree where leakage might result; [49 CFR 195.55(a)(1)]

2. unintended movement or abnormal loading of a pipeline by environmental causes, such as an earthquake, landslide, or flood that impairs its serviceability; [49 CFR 195.55(a)(2)]

3. any material defect or physical damage that impairs the serviceability of a pipeline; [49 CFR 195.55(a)(3)]

4. any malfunction or operating error that causes the pressure of a pipeline to rise above 110 percent of its maximum operating pressure; [49 CFR 195.55(a)(4)]

5. a leak in a pipeline that constitutes an emergency; [49 CFR 195.55(a)(5)]

6. any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline. [49 CFR 195.55(a)(6)]

B. A report is not required for any safety-related condition that: [49 CFR 195.55(b)]

1. exist on a pipeline that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway, or that occur offshore, or at on-shore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water; [49 CFR 195.55(b)(1)]

2. is an accident that is required to be reported under §30125 or results in such an accident before the deadline for filing the safety-related condition report; or [49 CFR 195.55(b)(2)]

3. is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for all conditions under §30133.A.l other than localized corrosion pitting on an effectively coated and cathodically protected pipeline. [49 CFR 195.55(b)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 27:1524 (September 2001), LR 29:2811 (December 2003).

§30135. Filing Safety-Related Condition Reports [49 CFR 195.56]

A. Each report of a safety-related condition under §30133.A must be filed (received by the commissioner and administrator) in writing within five working days (not including Saturday, Sunday, or federal holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by electronic mail to InformationResourcesManager@dot.gov, or by facsimile at (202) 366-7128 and to the Commissioner of Conservation by electronic mail to PipelineInspectors@la.gov. [49 CFR 195.56(a)]

B. The report must be headed "Safety-Related Condition Report" and provide the following information: [49 CFR 195.56(b)]

1. name and principal address of operator; [49 CFR 195.56(b)(1)]

2. date of report; [49 CFR 195.56(b)(2)]

3. name, job title, and business telephone number of person submitting the report; [49 CFR 195.56(b)(3)]

4. name, job title, and business telephone number of person who determined that the condition exists; [49 CFR 195.56(b)(4)]

5. date condition was discovered and date condition was first determined to exist; [49 CFR 195.56(b)(5)]

6. location of condition, with reference to the state (and town, city, or parish) or offshore site, and as appropriate nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline; [49 CFR 195.56(b)(6)]

7. description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored; [49 CFR 195.56(b)(7)]

8. the corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action. [49 CFR 195.56(b)(8)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 18:863 (August 1992), LR 20:440 (April 1994), LR 28:85 (January 2002), LR 29:2812 (December 2003), LR 35:2795 (December 2009), LR 44:1023 (June 2018).

§30140. Report Submission Requirements [49 CFR 195.58]

A. General. Except as provided in Subsection B of this Section, an operator must submit each report required by this part electronically to PHMSA at http://opsweb.phmsa.dot.gov unless an alternative reporting method is authorized in accordance with Subsection D of this Section. [49 CFR 195.58(a)]

1. Each report required by §30140.A, for intrastate facilities subject to the jurisdiction of the Office of Conservation, must also be submitted to Office of Conservation, P.O. Box 94275, Baton Rouge, LA 70804-9275.

a. Annual report information must only include data for intrastate facilities subject to the jurisdiction of the Office of Conservation.

B. Exceptions. An operator is not required to submit a safety-related condition report (§30135) electronically. [49 CFR 195.58 (b)]

C. Safety-Related Conditions. An operator must submit concurrently to the applicable State agency a safety-related condition report required by §30133 for an intrastate pipeline or when the state agency acts as an agent of the secretary with respect to interstate pipelines. [49 CFR 195.58(c)]

D. Alternate Reporting Method. If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE., Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method.

An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at (202) 366-8075, or electronically to informationresourcesmanager@dot.gov to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received. [49 CFR 195.58(d)]

E. National Pipeline Mapping System (NPMS). An operator must provide NPMS data to the address identified in the NPMS Operator Standards Manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595. [49 CFR 195.58(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2812 (December 2003), amended LR 33:469 (March 2007), LR 35:2795 (December 2009), LR 38:104 (January 2012), LR 44:1024 (June 2018).

§30141. Abandonment or Deactivation of Facilities. [49 CFR 195.59]

A. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility. [49 CFR 195.59]

1. The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions". To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at http://www.npms.PHMSA.dot.gov or contact the NPMS National Repository at (703) 317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax, or e-mail to the Office of Pipeline Safety, Pipeline Hazardous Materials Safety Administration, Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; fax (202) 366-4566; e-mail, "*InformationResourcesManager@PHMSA.dot.gov*". The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws [49 CFR 195.59(a)].

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2813 (December 2003), amended LR 33:469 (March 2007), LR 35:2796 (December 2009).

§30142. Operator Assistance in Investigation [49 CFR 195.60]

A. If the Department of Natural Resources investigates an accident, the operator involved shall make available to the representative of the department all records and information that in any way pertain to the accident, and shall afford all reasonable assistance in the investigation of the accident. [49 CFR 195.60]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2813 (December 2003).

§30143. National Pipeline Mapping System [49 CFR 195.61]

A. Each operator of a hazardous liquid pipeline facility must provide the following geospatial data to PHMSA for that facility:

1. geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595; [49 CFR 195.61(a)(1)]

2. the name of and address for the operator; [49 CFR 195.61(a)(2)]

3. the name and contact information of a pipeline company employee, to be displayed on a public website, who will serve as a contact for questions from the general public about the operator's NPMS data. [49 CFR 195.61(a)(3)]

B. This information must be submitted each year, on or before June 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must refer to the information provided in the NPMS Operator Standards manual available at www.npms.phmsa.dot.gov or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595. [49 CFR 195.61(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 44:1024 (June 2018).

§30145. OMB Control Number Assigned to Information Collection [49 CFR 195.63]

A. The control number assigned by the Office of Management and Budget to the hazardous liquid pipeline information collection pursuant to the Paperwork Reduction Act are 2137-0047, 2137-0601, 2137-0604, 2137-0605, 2137-0618, and 2137-0622. [49 CFR 195.63]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2813 (December 2003), amended LR 38:104 (January 2012).

§30146. National Registry of Pipeline and LNG Operators [49 CFR 195.64]

A. OPID Request. Effective January 1, 2012, each operator of a hazardous liquid pipeline or pipeline facility must obtain from PHMSA an operator identification number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID or a change to an OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline and LNG Operators in accordance with §30140. For intrastate facilities subject to the jurisdiction of the Office of Conservation, the operator must concurrently file an online OR-1 Submission (Operator Registration) for Pipeline Safety with the same name as the OPID request at http://www.sonris.com. Each operator must validate the OR-1 annually by January 1 each year. [49 CFR 195.64(a)]

B. OPID Validation. An operator who has already been assigned one or more OPID by January 1, 2011 must validate the information associated with each such OPID through the National Registry of Pipeline and LNG Operators at http://opsweb.phmsa.dot.gov, and correct that information as necessary, no later than June 30, 2012. [49 CFR 195.64(b)]

C. Changes. Each operator must notify PHMSA electronically through the National Registry of Pipeline and LNG Operators at http://opsweb.phmsa.dot.gov, of certain events. For intrastate facilities subject to the jurisdiction of the Office of Conservation, a copy must also be submitted to Office of Conservation, P.O. Box 94275, Baton Rouge, LA 70804-9275 or by electronic mail to PipelineInspectors@la.gov. Any change in an operator name, the operator must concurrently file an online OR-1 Submission for Pipeline Safety with the same name as the OPID operator name at http://www.sonris.com [49 CFR 195.64(c)]

1. An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs: [49 CFR 195.64(c)(1)]

a. construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable; [49 CFR 195.64(c)(1)(i)]

b. construction of 10 or more miles of a new hazardous liquid or carbon dioxide pipeline; [49 CFR 195.64(c)(1)(ii)]

c. reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or [49 CFR 195.64(c)(1)(iii)]

d. A pipeline converted for service under § 30111, or a change in commodity as reported on the annual report as required by §30124. [49 CFR 195.64(c)(1)(iv)]

2. An operator must notify PHMSA of any following event not later than 60 days after the event occurs: [49 CFR 195.64(c)(2)]

a. a change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this Subpart covering pipeline facilities operated under multiple OPIDs. [49 CFR 195.64(c)(2)(i)]

b. a change in the name of the operator; [49 CFR 195.64(c)(2)(ii)]

c. a change in the entity (e.g., company, municipality) responsible for operating an existing pipeline, pipeline segment, or pipeline facility; [49 CFR 195.64(c)(2)(iii)]

d. the acquisition or divestiture of 50 or more miles of pipeline or pipeline system subject to this subpart; or [49 CFR 195.64(c)(2)(iv)]

e. the acquisition or divestiture of an existing pipeline facility subject to this Subpart. [49 CFR 195.64(c)(2)(v)]

D. Reporting. An operator must use the OPID issued by PHMSA for all reporting requirements covered under this Subpart and for submissions to the National Pipeline Mapping System. [49 CFR 195.64(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 38:104 (January 2012), amended LR 44:1024 (June 2018), LR 46:1605 (November 2020).

§30147. Safety Data Sheets [49 CFR 195.65]

A. Each owner or operator of a hazardous liquid pipeline facility, following an accident involving a pipeline facility that results in a hazardous liquid spill, must provide safety data sheets on any spilled hazardous liquid to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders within 6 hours of a telephonic or electronic notice of the accident to the National Response Center. [49 CFR 195.65(a)].

B. Definitions. In this section: [49 CFR 195.65(b)].

1. Federal On-Scene Coordinator. The term *federal on-scene coordinator* has the meaning given such term in section 311(a) of the Federal Water Pollution Control Act (33 U.S.C. 1321(a)). [49 CFR 195.65(b)(1)]

2. National Response Center. The term *national response center* means the center described under 40 CFR 300.125(a). [49 CFR 195.65(b)(2)]

3. Safety Data Sheet. The term *safety data sheet* means a safety data sheet required under 29 CFR 1910.1200. [49 CFR 195.65(b)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 46:1605 (November 2020).

Subchapter C. Design Requirements [49 CFR Part 195 Subpart C]

§30153. Scope [49 CFR 195.100]

A. This Subchapter prescribes minimum design requirements for new pipeline systems constructed with steel pipe and for relocating, replacing, or otherwise changing existing systems constructed with steel pipe. However, it does not apply to the movement of line pipe covered by §30424. [49 CFR 195.100]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 29:2813 (December 2003).

§30155. Qualifying Metallic Components Other than Pipe [49 CFR 195.101]

A. Notwithstanding any requirement of the Subchapter which incorporates by reference an edition of a document listed in §30107, a metallic component other than pipe manufactured in accordance with any other edition of that document is qualified for use if: [49 CFR 195.101]

1. it can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and [49 CFR 195.101(a)]

2. the edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §30107: [49 CFR 195.101(b)]

a. pressure testing; [49 CFR 195.101(b)(1)]

b. materials; and [49 CFR 195.101(b)(2)]

c. pressure and temperature rating. [49 CFR 195.101(b)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 29:2814 (December 2003).

§30157. Design Temperature [49 CFR 195.102]

A. Material for components of the system must be chosen for the temperature environment in which the components will be used so that the pipeline will maintain its structural integrity. [49 CFR 195.102(a)]

B. Components of carbon dioxide pipelines that are subject to low temperatures during normal operation because of rapid pressure reduction or during the initial fill of the line must be made of materials that are suitable for those low temperatures. [49 CFR 195.102(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 18:864 (August 1992), LR 29:2814 (December 2003).

§30159. Variations in Pressure [49 CFR 195.104]

A. If, within a pipeline system, two or more components are to be connected at a place where one will operate at a higher pressure than another, the system must be designed so that any component operating at the lower pressure will not be over-stressed. [49 CFR 195.104]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 29:2814 (December 2003).

§30161. Internal Design Pressure [49 CFR 195.106]

A. Internal design pressure for the pipe in a pipeline is determined in accordance with the following formula:

$$P = (2\ St/D) \times E \times F$$

P = internal design pressure in p.s.i. (kPa) gauge.
S = yield strength in pounds per square inch (kPa) determined in accordance with §30161.B.
t = nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with §30161.C.
D = nominal outside diameter of the pipe in inches (millimeters).
E = seam joint factor determined in accordance with §30161.E.
F = a design factor of 0.72, except that a design factor of 0.60 is used for pipe, including risers, on a platform located off-shore or on a platform in inland navigable waters, and 0.54 is used for pipe that has been subjected to cold expansion to meet the specified minimum yield strength and is subsequently heated, other than by welding or stress relieving as a part of welding, to temperature higher than 900°F (482°C) for any period of time or over 600°F (316°C) for more than one hour. [49 CFR 195.106(a)]

B. The yield strength to be used in determining the internal design pressure under §30161.A is the specified minimum yield strength. If the specified minimum yield strength is not known, the yield strength to be used in the design formula is one of the following: [49 CFR 195.106(b)]

1. the yield strength determined by performing all of the tensile tests of API Specification 5L on randomly

selected specimens with the following number of tests: [49 CFR 195.106(b)(1)(i)]

Pipeline Size	Number of Tests
Less than 6-5/8 in. (168.3 mm) nominal outside diameter	One test for each 200 lengths
6-5/8 through 12-3/4 in. (168 through 323 mm.) nominal outside diameter	One test for each 100 lengths
Larger than 12-3/4 in. (324 mm.) nominal outside diameter	One test for each 50 lengths

2. if the average yield-tensile ratio exceeds 0.85, the yield strength shall be taken as 24,000 psi (165,474 kPa). If the average yield tensile ratio is 0.85 or less, the yield strength of the pipe is taken as the lower of the following: [49 CFR 195.106(b)(1)(ii)]

a. eighty percent of the average yield strength determined by the tensile tests; [49 CFR 195.106(b)(1)(ii)(A)]

b. the lowest yield strength determined by the tensile tests; [49 CFR 195.106(b)(1)(ii)(B)]

3. if the pipe is not tensile tested as provided in Subsection B, the yield strength shall be taken as 24,000 psi (165,474 kPa). [49 CFR 195.106(b)(2)]

C. If the nominal wall thickness to be used in determining internal design pressure under §30161.A is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end. However, if the pipe is of uniform grade, size and thickness, only 10 individual lengths or 5 percent of all lengths, whichever is greater, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness may not be more than 1.14 times the smallest measurement taken on pipe that is less than 20 in. (508 mm) nominal outside diameter, nor more than 1.11 times the smallest measurement taken on pipe that is 20 in. (508 mm) or more in nominal outside diameter. [49 CFR 195.106(c)]

D. The minimum wall thickness of the pipe may not be less than 87.5 percent of the value used for nominal wall thickness in determining the internal design pressure under §30161.A. In addition, the anticipated external loads and external pressures that are concurrent with internal pressure must be considered in accordance with §30163 and §30165 and, after determining the internal design pressure, the nominal wall thickness must be increased as necessary to compensate for these concurrent loads and pressures. [49 CFR 195.106(d)]

E. The seam joint factor used in §30161.A is determined in accordance with the following standards incorporated by reference (see §30107). [49 CFR 195.106(e)(1)]

Specification	Pipe Class	Seam Joint Factor
ASTM A53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace lap welded	0.80
	Furnace butt welded	0.60
ASTM A106/	Seamless	1.00
ASTM A333/A333M	Seamless	1.00
	Welded	1.00
ASTM A381	Double submerged arc welded	1.00
ASTM A671/A671M	Electric fusion welded	1.00
ASTM A672/A672M	Electric fusion welded	1.00
ASTM A691/A691M	Electric fusion welded	1.00
ANSI /API 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace lap welded	0.80
	Furnace butt welded	0.60

2. The seam joint factor for pipe which is not covered by this Subsection must be approved by the commissioner/ administrator. [49 CFR 195.106(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 20:441 (April 1994), LR 21:817 (August 1995), LR 27:1525 (September 2001), LR 29:2814 (December 2003), repromulgated LR 30:259 (February 2004), amended LR 44:1024 (June 2018).

§30163. External Pressure [49 CFR 195.108]

A. Any external pressure that will be exerted on the pipe must be provided for in designing a pipeline system. [49 CFR 195.108]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 29:2815 (December 2003).

§30165. External Loads [49 CFR 195.110]

A. Anticipated external loads (e.g., earthquakes, vibration, thermal expansion, and contraction) must be provided for in designing a pipeline system. In providing for expansion and flexibility, Section 419 of ASME/ANSI B31.4 must be followed. [49 CFR 195.110(a)]

B. The pipe and other components must be supported in such a way that the support does not cause excess localized stresses. In designing attachments to pipe, the added stress to the wall of the pipe must be computed and compensated for. [49 CFR 195.110(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 20:441 (April 1994), LR 29:2815 (December 2003).

§30167. Fracture Propagation [49 CFR 195.111]

A. A carbon dioxide pipeline system must be designed to mitigate the effects of fracture propagation. [49 CFR 195.111]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 18:864 (August 1992), amended LR 29:2815 (December 2003).

§30169. New Pipe [49 CFR 195.112]

A. Any new pipe installed in a pipeline system must comply with the following. [49 CFR 195.112]

1. The pipe must be made of steel of the carbon, low alloy-high strength, or alloy type that is able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system. [49 CFR 195.112(a)]

2. The pipe must be made in accordance with a written pipe specification that sets forth the chemical requirements for the pipe steel and mechanical tests for the pipe to provide pipe suitable for the use intended. [49 CFR 195.112(b)]

3. Each length of pipe with a nominal outside diameter of 4 1/2 in. (114.3 mm) or more must be marked on the pipe or pipe coating with the specification to which it was made, the specified minimum yield strength or grade, and the pipe size. The marking must be applied in a manner that does not damage the pipe or pipe coating and must remain visible until the pipe is installed. [49 CFR 195.112(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 21:817 (August 1995), LR 27:1525 (September 2001), LR 29:2815 (December 2003).

§30171. Used Pipe [49 CFR 195.114]

A. Any used pipe installed in a pipeline system must comply with §30169.A.1-2 and the following. [49 CFR 195.114]

1. The pipe must be of a known specification and the seam joint factor must be determined in accordance with §30161.E. If the specified minimum yield strength or the wall thickness is not known, it is determined in accordance with §30161.B or §30161.C as appropriate. [49 CFR 195.114(a)]

2. There may not be any: [49 CFR 195.114(b)]

a. buckles; [49 CFR 195.114(b)(1)]

b. cracks, grooves, gouges, dents, or other surface defects that exceed the maximum depth of such a defect permitted by the specification to which the pipe was manufactured; or [49 CFR 195.114(b)(2)]

c. corroded areas where the remaining wall thickness is less than the minimum thickness required by the tolerances in the specification to which the pipe was manufactured. However, pipe that does not meet the requirements of §30171.A.2.c may be used if the operating pressure is reduced to be commensurate with the remaining wall thickness. [49 CFR 195.114(b)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 29:2815 (December 2003).

§30173. Valves [49 CFR 195.116]

A. Each valve installed in a pipeline system must comply with the following. [49 CFR 195.116]

1. The valve must be of a sound engineering design. [49 CFR 195.116(a)]

2. Materials subject to the internal pressure of the pipeline system, including welded and flanged ends, must be compatible with the pipe or fittings to which the valve is attached. [49 CFR 195.116(b)]

3. Each part of the valve that will be in contact with the carbon dioxide or hazardous liquid stream must be made of materials that are compatible with carbon dioxide or each hazardous liquid that it is anticipated will flow through the pipeline system. [49 CFR 195.116(c)]

4. Each valve must be both hydrostatically shell tested and hydrostatically seat tested without leakage to at least the requirements set forth in Section 11 of ANSI/API 6D (incorporated by reference, see §30107). [49 CFR 195.116(d)]

5. Each valve other than a check valve must be equipped with a means for clearly indicating the position of the valve (open, closed, etc.). [49 CFR 195.116(e)]

6. Each valve must be marked on the body or the nameplate, with at least the following: [49 CFR 195.116(f)]

a. manufacturer's name or trademark; [49 CFR 195.116(f)(1)]

b. class designation or the maximum working pressure to which the valve may be subjected; [49 CFR 195.116(f)(2)]

c. body material designation (the end connection material, if more than one type is used); and [49 CFR 195.116(f)(3)]

d. nominal valve size. [49 CFR 195.116(f)(4)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 18:864 (August 1992), LR 29:2816 (December 2003), LR 33:469 (March 2007), LR 35:2796 (December 2009), LR 38:105 (January 2012), LR 44:1024 (June 2018).

§30175. Fittings [49 CFR 195.118]

A. Butt-welding type fittings must meet the marking, end preparation, and the bursting strength requirements of

ASME/ANSI B16.9 or MSS SP-75 (incorporated by reference, see §30107). [49 CFR 195.118(a)]

B. There may not be any buckles, dents, cracks, gouges, or other defects in the fitting that might reduce the strength of the fitting. [49 CFR 195.118(b)]

C. The fitting must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system to which it is attached. [49 CFR 195.118(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 20:441 (April 1994), LR 29:2816 (December 2003), LR 44:1024 (June 2018).

§30177. Passage of Internal Inspection Devices [49 CFR 195.120]

A. General. Except as provided in Subsection B and C of this Section, each new pipeline and each main line section of a pipeline where the line pipe, valve, fitting or other line component is replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102 (incorporated by reference, see §30107. [49 CFR 195.120(a)]

B. Exceptions. This Section does not apply to: [49 CFR 195.120(b)]

1. manifolds; [49 CFR 195.120(b)(1)]

2. station piping such as at pump stations, meter stations, or pressure reducing stations; [49 CFR 195.120(b)(2)]

3. piping associated with tank farms and other storage facilities; [49 CFR 195.120(b)(3)]

4. cross-overs; [49 CFR 195.120(b)(4)]

5. pipe for which an instrumented internal inspection device is not commercially available; and [49 CFR 195.120(b)(5)]

6. offshore pipelines, other than main lines 10 inches (254 mm) or greater in nominal diameter, that transport liquids to onshore facilities. [49 CFR 195.120(b)(6)]

C. Impracticability. An operator may file a petition under §190.9 of 49 CFR and Chapter 313 of this Subpart for a finding that the requirements in Subsection A of this Section should not be applied to a pipeline for reasons of impracticability. [49 CFR 195.120(c)]

D. Emergencies. An operator need not comply with Subsection A of this Section in constructing a new or replacement segment of a pipeline in an emergency. Within 30 days after discovering the emergency, the operator must file a petition under §190.9 of 49 CFR and Chapter 313 of this Subpart for a finding that requiring the design and construction of the new or replacement pipeline segment to accommodate passage of instrumented internal inspection devices would be impracticable as a result of the emergency. If PHMSA denies the petition, within 1 year after the date of the notice of the denial, the operator must modify the new or replacement pipeline segment to allow passage of instrumented internal inspection devices. [49 CFR 195.120(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 21:817 (August 1995), LR 27:1526 (September 2001), LR 29:2816 (December 2003), LR 44:1025 (June 2018), LR 46:1606 (November 2020).

§30179. Fabricated Branch Connections [49 CFR 195.122]

A. Each pipeline system must be designed so that the addition of any fabricated branch connections will not reduce the strength of the pipeline system. [49 CFR 195.122]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 29:2816 (December 2003).

§30181. Closures [49 CFR 195.124]

A. Each closure to be installed in a pipeline system must comply with the 2007 ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, see §30107) and must have pressure and temperature ratings at least equal to those of the pipe to which the closure is attached. [49 CFR 195.124]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 29:2816 (December 2003), LR 44:1025 (June 2018).

§30183. Flange Connection [49 CFR 195.126]

A. Each component of a flange connection must be compatible with each other component and the connection as a unit must be suitable for the service in which it is to be used. [49 CFR 195.126]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 29:2817 (December 2003).

§30185. Station Piping [49 CFR 195.128]

A. Any pipe to be installed in a station that is subject to system pressure must meet the applicable requirements of this Subchapter. [49 CFR 195.128]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 29:2817 (December 2003).

§30187. Fabricated Assemblies [49 CFR 195.130]

A. Each fabricated assembly to be installed in a pipeline system must meet the applicable requirements of this Subchapter. [49 CFR 195.130]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 29:2817 (December 2003).

§30189. Design and Construction of Above Ground Breakout Tanks [49 CFR 195.132]

A. Each above ground breakout tank must be designed and constructed to withstand the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads. [49 CFR 195.132(a)]

B. For aboveground breakout tanks first placed in service after October 2, 2000, compliance with Subsection A. of this Section requires one of the following. [49 CFR 195.132(b)]

1. Shop-fabricated, vertical, cylindrical, closed top, welded steel tanks with nominal capacities of 90 to 750 barrels (14.3 to 119.2 m^3) and with internal vapor space pressures that are approximately atmospheric must be designed and constructed in accordance with API Spec 12F (incorporated by reference, see §30107). [49 CFR 195.132(b)(1)]

2. Welded, low-pressure [i.e., internal vapor space pressure not greater than 15 psig (103.4 kPa)], carbon steel tanks that have wall shapes that can be generated by a single vertical axis of revolution must be designed and constructed in accordance with API Std 620(incorporated by reference, see §30107). [49 CFR 195.132(b)(2)]

3. Vertical, cylindrical, welded steel tanks with internal pressures at the tank top approximately atmospheric pressures [i.e., internal vapor space pressures not greater than 2.5 psig (17.2 kPa), or not greater than the pressure developed by the weight of the tank roof] must be designed and constructed in accordance with API Std 650 (incorporated by reference, see §30107). [49 CFR 195.132(b)(3)]

4. High pressure steel tanks [i.e., internal gas or vapor space pressures greater than 15 psig (103.4 kPa)] with a nominal capacity of 2000 gallons (7571 liters) or more of liquefied petroleum gas (LPG) must be designed and constructed in accordance with API Std 2510(incorporated by reference, see §30107). [49 CFR 195.132(b)(4)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 27:1526 (September 2001), amended LR 29:2817 (December 2003), LR 44:1025 (June 2018).

§30191. Leak Detection [49 CFR 195.134]

A. Scope. This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid). [49 CFR 195.134(a)]

B. General [49 CFR 195.134(b)]

1. For each pipeline constructed prior to October 1, 2019. Each pipeline must have a system for detecting leaks that complies with the requirements in §30444 by October 1, 2024. [49 CFR 195.134(b)(1)]

2. For each pipeline constructed on or after October 1, 2019. Each pipeline must have a system for detecting leaks that complies with the requirements in §30444 by October 1, 2020. [49 CFR 195.134(b)(2)]

C. CPM Leak Detection Systems. A new computational pipeline monitoring (CPM) leak detection system or replaced component of an existing CPM system must be designed in accordance with the requirements in section 4.2 of API RP 1130 (incorporated by reference, see §30107) and any other applicable design criteria in that standard. [49 CFR 195.134(c)]

D. Exception. The requirements of Subsection B of this Section do not apply to offshore gathering or regulated rural gathering lines. [49 CFR 195.134(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 27:1526 (September 2001), amended LR 29:2817 (December 2003), LR 44:1025 (June 2018), LR 46:1606 (November 2020).

Chapter 302. Transportation of Hazardous Liquids by Pipeline—Construction [49 CFR Part 195 Subpart D]

§30200. Scope [49 CFR 195.200]

A. This Chapter prescribes minimum requirements for constructing new pipeline systems with steel pipe, and for relocating, replacing, or otherwise changing existing pipeline systems that are constructed with steel pipe. However, this Chapter does not apply to the movement of pipe covered by §30424. [49 CFR 195.200]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2817 (December 2003).

§30202. Compliance with Specifications or Standards [49 CFR 195.202]

A. Each pipeline system must be constructed in accordance with comprehensive written specifications or standards that are consistent with the requirements of this Subpart. [49 CFR 195.202]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2817 (December 2003).

§30204. Inspection—General [49 CFR 195.204]

A. Inspection must be provided to ensure the installation of pipe or pipeline systems in accordance with the requirements of this Chapter. Any operator personnel used to perform the inspection must be trained and is qualified in the phase of construction to be inspected. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operating personnel who are involved in other construction tasks. [49 CFR 195.204]

B. Each operator shall notify the Pipeline Safety Section of the Office of Conservation, Louisiana Department of Natural Resources, by electronic mail at PipelineInspectors@la.gov of proposed pipeline construction at least seven days prior to commencement of said construction.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2817 (December 2003), repromulgated LR 30:260 (February 2004), amended LR 44:1025 (June 2018).

§30205. Repair, Alteration and Reconstruction of Aboveground Breakout Tanks That Have Been in Service [49 CFR 195.205]

A. Aboveground breakout tanks that have been repaired, altered, or reconstructed and returned to service must be capable of withstanding the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads. [49 CFR 195.205(a)]

B. After October 2, 2000, compliance with Subsection A of this Section requires the following: [49 CFR 195.205(b)]

1. For tanks designed for approximate atmospheric pressure, constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated; and for tanks built to API Std 650 (incorporated by reference, see §30107) or its predecessor Standard 12C; repair, alteration and reconstruction must be in accordance with API Standard Std 653 (except section 6.4.3) (incorporated by reference, see §30107). [49 CFR 195.205(b)(1)]

2. For tanks built to API Spec 12F (incorporated by reference, see §30107) or API Std 620 (incorporated by reference, see §30107), the repair, alteration, and reconstruction must be in accordance with the design, welding, examination, and material requirements of those respective standards. [49 CFR 195.205(b)(2)]

3. For high pressure tanks built to API Std 2510 (incorporated by reference, see §30107), repairs, alterations, and reconstruction must be in accordance with API Std 510 (incorporated by reference, see §30107). [49 CFR 195.205(b)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2818 (December 2003), amended LR 44:1025 (June 2018).

§30206. Material Inspection [49 CFR 195.206]

A. No pipe or other component may be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability. [49 CFR 195.206]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2818 (December 2003).

§30207. Transportation of Pipe [49 CFR 195.207]

A. Railroad. In a pipeline operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless the transportation is performed in accordance with API RP 5L1 (incorporated by reference, see §30107). [49 CFR 195.207(a)]

B. Ship or Barge. In a pipeline operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways, unless the transportation is performed in accordance with API RP 5LW (incorporated by reference, see §30107). [49 CFR 195.207(b)]

C. Truck. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, see §30107).

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 38:105 (January 2012), amended LR 44:1026 (June 2018).

§30208. Welding of Supports and Braces [49 CFR 195.208]

A. Supports or braces may not be welded directly to pipe that will be operated at a pressure of more than 100 p.s.i. (689 Kpa) gage. [49 CFR 195.208]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2818 (December 2003).

§30210. Pipeline Location [49 CFR 195.210]

A. Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. [49 CFR 195.210(a)]

B. No pipeline may be located within 50 feet (15 meters) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate, or assemble, unless it is provided with at least 12 inches (305 millimeters) of cover in addition to that prescribed in §30248. [49 CFR 195.210(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2818 (December 2003).

§30212. Bending of Pipe [49 CFR 195.212]

A. Pipe must not have a wrinkle bend. [49 CFR 195.212(a)]

B. Each field bend must comply with the following: [49 CFR 195.212(b)]

1. a bend must not impair the serviceability of the pipe; [49 CFR 195.212(b)(1)]

2. each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage; [49 CFR 195.212(b)(2)]

3. on pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless: [49 CFR 195.212(b)(3)]

a. the bend is made with an internal bending mandrel; or [49 CFR 195.212(b)(3)(i)]

b. the pipe is 12-3/4 in. (324 mm.) or less nominal outside diameter or has a diameter to wall thickness ratio less than 70. [49 CFR 195.212(b)(3)(ii)]

C. Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. [49 CFR 195.212(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2818 (December 2003).

§30214. Welding Procedures [49 CFR 195.214]

A. Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see §30107), or Section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see §30107). The quality of the test welds used to qualify the welding procedures must be determined by destructive testing. [49 CFR 195.214(a)].

B. Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used. [49 CFR 195.214(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2818 (December 2003), amended LR 31:677 (March 2005), LR 33:469 (March 2007), LR 44:1026 (June 2018), LR 46:1606 (November 2020).

§30216. Welders: Miter Joints [49 CFR 195.216]

A. A miter joint is not permitted (not including deflections up to three degrees that are caused by misalignment). [49 CFR 195.216]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2818 (December 2003).

§30222. Welders—Qualification of Welders [49 CFR 195.222]

A. Each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see §30107), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC), (incorporated by reference, see §30107) except that a welder or welding operator qualified under an earlier edition than listed in §30107, may weld but may not requalify under that earlier edition. [49 CFR 195.222(a)].

B. No welder or welding operator may weld with a particular welding process unless, within the preceding six calendar months, the welder or welding operator has: [49 CFR 195.222(b)]

1. engaged in welding with that process; and [49 CFR 195.222(b)(1)]

2. had one weld tested and found acceptable under section 9 or appendix A of API Std 1104 (incorporated by reference, see §30107). [49 CFR 195.222(b)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2818 (December 2003), amended LR 31:677 (March 2005), LR 33:469 (March 2007), LR 44:1026 (June 2018), LR 46:1606 (November 2020).

§30224. Welding: Weather [49 CFR 195.224]

A. Welding must be protected from weather conditions that would impair the quality of the completed weld. [49 CFR 195.224]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2819 (December 2003).

§30226. Welding: Arc Burns [49 CFR 195.226]

A. Each arc burn must be repaired. [49 CFR 195.226(a)]

B. An arc burn may be repaired by completely removing the notch by grinding, if the grinding does not reduce the remaining wall thickness to less than the minimum thickness required by the tolerances in the specification to which the pipe is manufactured. If a notch is not repairable by grinding, a cylinder of the pipe containing the entire notch must be removed. [49 CFR 195.226(b)]

C. A ground may not be welded to the pipe or fitting that is being welded. [49 CFR 195.226(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2819 (December 2003).

§30228. Welds and Welding Inspection: Standards of Acceptability [49 CFR 195.228]

A. Each weld and welding must be inspected to insure compliance with the requirements of this Chapter. Visual inspection must be supplemented by nondestructive testing. [49 CFR 195.228(a)]

B. The acceptability of a weld is determined according to the standards in Section 9 or Appendix A of API Std 1104. Appendix A of API Std 1104 may not be used to accept cracks. [49 CFR 195.228(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2819 (December 2003), amended LR 31:677 (March 2005), LR 35:2796 (December 2009), LR 44:1026 (June 2018).

§30230. Welds: Repair or Removal of Defects [49 CFR 195.230]

A. Each weld that is unacceptable under §30228 must be removed or repaired. Except for welds on an off-shore pipeline being installed from a pipelay vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length. [49 CFR 195.230(a)]

B. Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability. [49 CFR 195.230(b)]

C. Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under §30214. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair. [49 CFR 195.230(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2819 (December 2003).

§30234. Welds: Nondestructive Testing [49 CFR 195.234]

A. A weld may be nondestructively tested by any process that will clearly indicate any defects that may affect the integrity of the weld. [49 CFR 195.234(a)]

B. Any nondestructive testing of welds must be performed: [49 CFR 195.234(b)]

1. in accordance with a written set of procedures for nondestructive testing; and [49 CFR 195.234(b)(1)]

2. with personnel that have been trained in the established procedures and in the use of the equipment employed in the testing. [49 CFR 195.234(b)(2)]

C. Procedures for the proper interpretation of each weld inspection must be established to ensure the acceptability of the weld under §30228. [49 CFR 195.234(c)]

D. During construction, at least 10 percent of the girth welds made by each welder and welding operator during each welding day must be nondestructively tested over the entire circumference of the weld. [49 CFR 195.234(d)]

E. All girth welds installed each day in the following locations must be nondestructively tested over their entire circumference, except that when nondestructive testing is impracticable for a girth weld, it need not be tested if the number of girth welds for which testing is impracticable does not exceed 10 percent of the girth welds installed that day: [49 CFR 195.234(e)]

1. at any onshore location where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water, and any offshore area; [49 CFR 195.234(e)(1)]

2. within railroad or public road rights-of-way; [49 CFR 195.234(e)(2)]

3. at overhead road crossings and within tunnels; [49 CFR 195.234(e)(3)]

4. within the limits of any incorporated subdivision of a state government; and [49 CFR 195.234(e)(4)]

5. within populated areas, including, but not limited to, residential subdivisions, shopping centers, schools, designated commercial areas, industrial facilities, public institutions, and places of public assembly. [49 CFR 195.234(e)(5)]

F. When installing used pipe, 100 percent of the old girth welds must be nondestructively tested. [49 CFR 195.234(f)]

G. At pipeline tie-ins, including tie-ins of replacement sections, 100 percent of the girth welds must be nondestructively tested. [49 CFR 195.234(g)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2819 (December 2003), amended LR 44:1026 (June 2018).

§30246. Installation of Pipe in a Ditch [49 CFR 195.246]

A. All pipe installed in a ditch must be installed in a manner that minimizes the introduction of secondary stresses and the possibility of damage to the pipe. [49 CFR 195.246(a)]

B. Except for pipe in the Gulf of Mexico and its inlets in waters less than 15 feet deep, all offshore pipe in water at least 12 feet deep (3.7 meters) but not more than 200 feet deep (61 meters) deep as measured from the mean low water must be installed so that the top of the pipe is below the underwater natural bottom (as determined by recognized and generally accepted practices) unless the pipe is supported by stanchions held in place by anchors or heavy concrete coating or protected by an equivalent means. [49 CFR 195.246(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2819 (December 2003), amended LR 31:677 (March 2005), LR 35:2796 (December 2009).

§30248. Cover over Buried Pipeline [49 CFR 195.248]

A. Unless specifically exempted in this Chapter, all pipe must be buried so that it is below the level of cultivation. Except as provided in §30248.B of this Section, the pipe must be installed so that the cover between the top of the pipe and the ground level, road bed, river bottom, or underwater natural bottom (as determined by recognized and generally accepted practices), as applicable, complies with the following table [49 CFR 195.248(a)].

Location	Cover (Inches)(Millimeters)	
	For Normal Excavation	For Rock Excavation[1]
Industrial, commercial and residential area	36 (914)	30 (762)
Crossings of inland bodies of water with a width of at least 100 ft. (30 meters) from high water mark to high water mark	48 (1219)	18 (457)
Drainage ditches at public roads and railroads	36 (914)	36 (914)
Deepwater port safety zone	48 (1219)	24 (610)
Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water	36 (914)	18 (457)
Other offshore areas under water less than 12 ft (3.7 meters) deep as measured from mean low water	36 (914)	18 (457)
Any other area	30 (762)	18 (457)

[1]Rock excavation is any excavation that requires blasting or removal by equivalent means.

B. Except for the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep, less cover than the minimum required by Subsection A of this Section and §30210 may be used if [49 CFR 195.248(b)]:

1. it is impracticable to comply with the minimum cover requirements; and [49 CFR 195.248(b)(1)]

2. additional protection is provided that is equivalent to the minimum required cover. [49 CFR 195.248(b)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2820 (December 2003), amended LR 31:678 (March 2005), LR 33:470 (March 2007).

§30250. Clearance between Pipe and Underground Structures [49 CFR 195.250]

A. Any pipe installed underground must have at least 12 inches (305 millimeters) of clearance between the outside of the pipe and the extremity of any other underground structure, except that for drainage tile the minimum clearance may be less than 12 inches (305 millimeters) but not less than 2 inches (51 millimeters). However, where 12 inches (305 millimeters) of clearance is impracticable, the clearance may be reduced if adequate provisions are made for corrosion control. [49 CFR 195.250]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2820 (December 2003).

§30252. Backfilling [49 CFR 195.252]

A. When a ditch for a pipeline is backfilled, it must be backfilled in a manner that: [49 CFR 195.252(a)]

1. provides firm support under the pipe; and [49 CFR 195.252(a)(1)]

2. prevents damage to the pipe and pipe coating from equipment or from the backfill material. [49 CFR 195.252(a)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2820 (December 2003), amended LR 31:678 (March 2005).

§30254. Above Ground Components [49 CFR 195.254]

A. Any component may be installed above ground in the following situations, if the other applicable requirements of this Subpart are complied with: [49 CFR 195.254(a)]

1. overhead crossing of highways, railroads, or body of water; [49 CFR 195.254(a)(1)]

2. spans over ditches and gullies; [49 CFR 195.254(a)(2)]

3. scraper traps or block valves; [49 CFR 195.254(a)(3)]

4. area under the direct control of the operator; [49 CFR 195.254(a)(4)]

5. in any area inaccessible to the public. [49 CFR 195.254(a)(5)]

B. Each component covered by §30254 must be protected from the forces exerted by the anticipated loads. [49 CFR 195.254(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2820 (December 2003).

§30256. Crossing of Railroads and Highways [49 CFR 195.256]

A. The pipe at each railroad or highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads. [49 CFR 195.256]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2820 (December 2003).

§30258. Valves: General [49 CFR 195.258]

A. Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering. [49 CFR 195.258(a)]

B. Each submerged valve located offshore or in inland navigable waters must be marked, or located by conventional survey techniques, to facilitate quick location when operation of the valve is required. [49 CFR 195.258(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2820 (December 2003).

§30260. Valves: Location [49 CFR 195.260]

A. A valve must be installed at each of the following locations: [49 CFR 195.260]

1. on the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency; [49 CFR 195.260(a)]

2. on each line entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities; [49 CFR 195.260(b)]

3. on each mainline at locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas; [49 CFR 195.260(c)]

4. on each lateral takeoff from a trunk line in a manner that permits shutting off the lateral without interrupting the flow in the trunk line; [49 CFR 195.260(d)]

5. on each side of a water crossing that is more than 100 feet (30 meters) wide from high-water mark to high-water mark unless the Commissioner and Administrator finds in a particular case that valves are not justified; [49 CFR 195.260(e)]

6. on each side of a reservoir holding water for human consumption. [49 CFR 195.260(f)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2821 (December 2003).

§30262. Pumping Equipment [49 CFR 195.262]

A. Adequate ventilation must be provided in pump station buildings to prevent the accumulation of hazardous vapors. Warning devices must be installed to warn of the presence of hazardous vapors in the pumping station building. [49 CFR 195.262(a)]

B. The following must be provided in each pump station: [49 CFR 195.262(b)]

1. safety devices that prevent overpressuring of pumping equipment, including the auxiliary pumping equipment within the pumping station; [49 CFR 195.262(b)(1)]

2. a device for the emergency shutdown of each pumping station; [49 CFR 195.262(b)(2)]

3. if power is necessary to actuate the safety devices, an auxiliary power supply. [49 CFR 195.262(b)(3)]

C. Each safety device must be tested under conditions approximating actual operations and found to function properly before the pumping station may be used. [49 CFR 195.262(c)]

D. Except for offshore pipelines, pumping equipment must be installed on property that is under the control of the operator and at least 50 ft. (15.2 m.) from the boundary of the pump station. [49 CFR 195.262(d)]

E. Adequate fire protection must be installed at each pump station. If the fire protection system installed requires the use of pumps, motive power must be provided for those pumps that are separate from the power that operates the station. [49 CFR 195.262(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2821 (December 2003).

§30264. Impoundment, Protection against Entry, Normal/Emergency Venting or Pressure/Vacuum Relief for Aboveground Breakout Tanks [49 CFR 195.264]

A. A means must be provided for containing hazardous liquids in the event of spillage or failure of an aboveground breakout tank. [49 CFR 195.264(a)]

B. After October 2, 2000, compliance with Subsection A of this Section requires the following for the aboveground breakout tank specified. [49 CFR 195.264(b)]

1. For tanks built to API Spec 12F, API Std 620, and others (such as API Standard 650(or its predecessor Standard 12C)), the installation of impoundment must be in accordance with the following sections of NFPA-30 (incorporated by reference, see §30107): [49 CFR 195.264(b)(1)]

a. impoundment around a breakout tank must be installed in accordance with Section 22.11.2; and [49 CFR 195.264(b)(1)(i)]

b. impoundment by drainage to a remote impounding area must be installed in accordance with Section 22.11.1. [49 CFR 195.264(b)(1)(ii)]

2. For tanks built to API Std 2510(incorporated by reference, see §30107), the installation of impoundment must be in accordance with Section 5 or 11 of API Std 2510. [49 CFR 195.264(b)(2)]

C. Aboveground breakout tank areas must be adequately protected against unauthorized entry. [49 CFR 195.264(c)]

D. Normal/emergency relief venting must be provided for each atmospheric pressure breakout tank. Pressure/vacuum-relieving devices must be provided for each low-pressure and high-pressure breakout tank. [49 CFR 195.264(d)]

E. For normal/emergency relief venting and pressure/vacuum-relieving devices installed on aboveground breakout tanks after October 2, 2000, compliance with Subsection D of this Section requires the following for the tanks specified. [49 CFR 195.264(e)]

1. Normal/emergency relief venting installed on atmospheric pressure tanks built to API Spec 12F must be in accordance with section 4, and Appendices B and C, of API Spec 12F (incorporated by reference, see §30107). [49 CFR 195.264(e)(1)]

2. Normal/emergency relief venting installed on atmospheric pressure tanks (such as those built to API Std 650 or its predecessor Standard 12C) must be in accordance with API Std 2000 (incorporated by reference, see §30107). [49 CFR 195.264(e)(2)]

3. Pressure-relieving and emergency vacuum relieving devices installed on low pressure tanks built to API Std 620 must be in accordance with Section 9 of API Std 620 (incorporated by reference, see §30107) and its references to the normal and emergency venting requirements in API Std 2000 (incorporated by reference, see §30107). [49 CFR 195.264(e)(3)]

4. Pressure and vacuum-relieving devices installed on high pressure tanks built to API Std 2510 must be in accordance with sections 7 or 11 of API Std 2510 (incorporated by reference, see §30107). [49 CFR 195.264(e)(4)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2821 (December 2003), amended LR 33:470 (March 2007), LR 35:2797 (December 2009), LR 38:105 (January 2012), LR 44:1026 (June 2018).

§30266. Construction Records [49 CFR 195.266]

A. A complete record that shows the following must be maintained by the operator involved for the life of each pipeline facility: [49 CFR 195.266]

1. the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld; [49 CFR 195.266(a)]

2. the amount, location, and cover of each size of pipe installed; [49 CFR 195.266(b)]

3. the location of each crossing of another pipeline; [49 CFR 195.266(c)]

4. the location of each buried utility crossing; [49 CFR 195.266(d)]

5. the location of each overhead crossing; [49 CFR 195.266(e)]

6. the location of each valve and corrosion test station. [49 CFR 195.266(f)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2822 (December 2003).

Chapter 303. Transportation of Hazardous Liquids by Pipeline—Pressure Testing [49 CFR Part 195 Subpart E]

§30300. Scope [49 CFR 195.300]

A. This Chapter prescribes minimum requirements for the pressure testing of steel pipelines. However, this Chapter does not apply to movement of pipe under §30424. [49 CFR 195.300]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2822 (December 2003).

§30302. General Requirements [49 CFR 195.302]

A. Except as otherwise provided in this Section and in §30305.B, no operator may operate a pipeline unless it has been pressure tested under this Chapter without leakage. In addition, no operator may return to service a segment of pipeline that has been replaced, relocated, or otherwise changed until it has been pressure tested under this Chapter without leakage. [49 CFR 195.302(a)]

B. Except for pipelines converted under §30111, the following pipelines may be operated without pressure testing under this Chapter. [49 CFR 195.302(b)]

1. Any hazardous liquid pipeline whose maximum operating pressure is established under §30406.A.5 that is: [49 CFR 195.302(b)(1)]

a. an interstate pipeline constructed before January 8, 1971; [49 CFR 195.302(b)(1)(i)]

b. an interstate offshore gathering line constructed before August 1, 1977; [49 CFR 195.302(b)(1)(ii)]

c. an intrastate pipeline constructed before October 21, 1985; or [49 CFR 195.302(b)(1)(iii)]

d. a low-stress pipeline constructed before August 11, 1994 that transports HVL. [49 CFR 195.302(b)(1)(iv)]

2. Any carbon dioxide pipeline constructed before July 12, 1991, that: [49 CFR 195.302(b)(2)]

a. has its maximum operating pressure established under §30406.A.5; or [49 CFR 195.302(b)(2)(i)]

b. is located in a rural area as part of a production field distribution system. [49 CFR 195.302(b)(2)(ii)]

3. Any low-stress pipeline constructed before August 11, 1994 that does not transport HVL. [49 CFR 195.302(b)(3)]

C. Except for pipelines that transport HVL onshore and low-stress pipelines, the following compliance deadlines apply to pipelines under Paragraph B.1 and Subparagraph B.2.a of this Section that have not been pressure tested under this Chapter. [49 CFR 195.302(c)]

1. Before December 7, 1998, for each pipeline each operator shall: [49 CFR 195.302(c)(1)]

a. plan and schedule testing, according to this subsection; or [49 CFR 195.302(c)(1)]

b. establish the pipelines maximum operating pressure under §30406.A.5. [49 CFR 195.302(c)(1)(ii)]

2. For pipelines scheduled for testing, each operator shall: [49 CFR 195.302(c)(2)]

a. before December 7, 2000, pressure test: [49 CFR 195.302(c)(2)(i)]

i. each pipeline identified by name, symbol, or otherwise that existing records show contains more than 50 percent by mileage (length) of electric resistance welded pipe manufactured before 1970; and [49 CFR 195.302(c)(2)(i)(A)]

ii. at least 50 percent of the mileage (length) of all other pipelines; and [49 CFR 195.302(c)(2)(i)(B)]

b. before December 7, 2003, pressure test the remainder of the pipeline mileage (length). [49 CFR 195.302(c)(2)(ii)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2822 (December 2003).

§30304. Test Pressure [49 CFR 195.304]

A. The test pressure for each pressure test conducted under this Chapter must be maintained throughout the part of the system being tested for at least four continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure and, in the case of a pipeline that is not visually inspected for leakage during the test, for at least an additional four continuous hours at a pressure equal to 110 percent, or more, of the maximum operating pressure. [49 CFR 195.304]

AUTHORITY NOTE: Promulgated in accordance with R.S.30:703

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2822 (December 2003).

§30305. Testing of Components [49 CFR 195.305]

A. Each pressure test under §30302 must test all pipe and attached fittings, including components, unless otherwise permitted by §30305.B. [49 CFR 195.305(a)]

B. A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under §30305.A if the manufacturer certifies that either: [49 CFR 195.305(b)]

1. the component was hydrostatically tested at the factory; or [49 CFR 195.305(b)(1)]

2. the component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory. [49 CFR 195.305(b)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2822 (December 2003).

§30306. Test Medium [49 CFR 195.306]

A. Except as provided in §30306.B, C, and D, water must be used as the test medium. [49 CFR 195.306(a)]

B. Except for offshore pipelines, liquid petroleum that does not vaporize rapidly may be used as the test medium if: [49 CFR 195.306(b)]

1. the entire pipeline section under test is outside of cities and other populated areas; [49 CFR 195.306(b)(1)]

2. each building within 300 feet (91 meters) of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50 percent of specified minimum yield strength; [49 CFR 195.306(b)(2)]

3. the test section is kept under surveillance by regular patrols during the test; and [49 CFR 195.306(b)(3)]

4. continuous communication is maintained along entire test section. [49 CFR 195.306(b)(4)]

C. Carbon dioxide pipelines may use inert gas or carbon dioxide as the test medium if: [49 CFR 195.306(c)]

1. the entire pipeline section under test is outside of cities and other populated areas; [49 CFR 195.306(c)(1)]

2. each building within 300 feet (91 meters) of the test section is unoccupied while the test pressure is equal to or greater than a pressure that produces a hoop stress of 50 percent of specified minimum yield strength; [49 CFR 195.306(c)(2)]

3. the maximum hoop stress during the test does not exceed 80 percent of specified minimum yield strength; [49 CFR 195.306(c)(3)]

4. continuous communication is maintained along entire test section; and [49 CFR 195.306(c)(4)]

5. the pipe involved is new pipe having a longitudinal joint factor of 1.00. [49 CFR 195.306(c)(5)]

D. Air or inert gas may be used as the test medium in low stress pipelines. [49 CFR 195.306(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2823 (December 2003).

§30307. Pressure Testing Aboveground Breakout Tanks [49 CFR 195.307]

A. For aboveground breakout tanks built to API Spec 12F (incorporated by reference, see §30107) and first placed in service after October 2, 2000, pneumatic testing must be in accordance with section 5.3 of API Spec 12 F. [49 CFR 195.307(a)]

B. For aboveground breakout tanks built to API Std 620 (incorporated by reference, see §30107) and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 7.18 of API Std 620. [49 CFR 195.307(b)]

C. For aboveground breakout tanks built to API Std 650 (incorporated by reference, see §30107) and first placed in service after October 2, 2000, testing must be in accordance with sections 7.3.5 and 7.3.6 of API Standard 650 (incorporated by reference, see §30107). [49 CFR 195.307(c)]

D. For aboveground atmospheric pressure breakout tanks constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated; and tanks that are returned to service after October 2, 2000, and are built to API Std 650 or its predecessor Standard 12C; the necessity for the hydrostatic testing of repair, alteration, and reconstruction is covered in section 12.3 of API Standard 653. [49 CFR 195.307(d)]

E. For aboveground breakout tanks built to API Std 2510 (incorporated by reference, see §30107) and first placed in service after October 2, 2000, pressure testing must be in accordance with 2007 ASME Boiler and Pressure Vessel Code (BPVC), (Section VIII, Division 1 or 2). [49 CFR 195.307(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2823 (December 2003), amended LR 33:470 (March 2007), LR 38:105 (January 2012), LR 44:1027 (June 2018).

§30308. Testing of Tie-Ins [49 CFR 195.308]

A. Pipe associated with tie-ins must be pressure tested, either with the section to be tied in or separately. [49 CFR 195.308]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2823 (December 2003).

§30310. Records [49 CFR 195.310]

A. A record must be made of each pressure test required by this Chapter, and the record of the latest test must be retained as long as the facility tested is in use. [49 CFR 195.310(a)]

B. The record required by §30310.A must include: [49 CFR 195.310(b)]

1. the pressure recording charts; [49 CFR 195.310(b)(1)]

2. test instrument calibration data; [49 CFR 195.310(b)(2)]

3. the name of the operator, the name of the person responsible for making the test, and the name of the test company used, if any; [49 CFR 195.310(b)(3)]

4. the date and time of the test; [49 CFR 195.310(b)(4)]

5. the minimum test pressure; [49 CFR 195.310(b)(5)]

6. the test medium; [49 CFR 195.310(b)(6)]

7. a description of the facility tested and the test apparatus; [49 CFR 195.310(b)(7)]

8. an explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts; [49 CFR 195.310(b)(8)]

9. where elevation differences in the section under test exceed 100 feet (30 meters), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section; and [49 CFR 195.310(b)(9)]

10. temperature of the test medium or pipe during the test period. [49 CFR 195.310(b)(10)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2823 (December 2003), amended LR 31:678 (March 2005).

Chapter 304. Transportation of Hazardous Liquids by Pipeline—Operation and Maintenance [49 CFR Part 195 Subpart F]

§30400. Scope [49 CFR 195.400]

A. This Chapter prescribes minimum requirements for operating and maintaining pipeline systems constructed with steel pipe. [49 CFR 195.400]

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HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2823 (December 2003).

§30401. General Requirements [49 CFR 195.401]

A. No operator may operate or maintain its pipeline systems at a level of safety lower than that required by this Chapter and the procedures it is required to establish under §30402.A. [49 CFR 195.401(a)]

B. An operator must make repairs on its pipeline system according to the following requirements. [49 CFR 195.401(b)]

1. Non Integrity Management Repairs. Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition. [49 CFR 195.401(b)(1)]

2. Integrity Management Repairs. When an operator discovers a condition on a pipeline covered under §30452, the operator must correct the condition as prescribed in §30452.H. [49 CFR 195.401(b)(2)]

3. Prioritizing Repairs. An operator must consider the risk to people, property, and the environment in prioritizing the correction of any conditions referenced in Paragraphs B.1 and 2 of this Section. [49 CFR 195.401(b)(3)]

C. Except as provided by §30111, no operator may operate any part of any of the following pipelines unless it was designed and constructed as required by this Subpart: [49 CFR 195.401(c)]

1. an interstate pipeline, other than a low-stress pipeline, on which construction was begun after March 31, 1970, that transports hazardous liquid; [49 CFR 195.401(c)(1)]

2. an interstate offshore gathering line, other than a low-stress pipeline, on which construction was begun after July 31, 1977, that transports hazardous liquid; [49 CFR 195.401(c)(2)]

3. an intrastate pipeline, other than a low-stress pipeline, on which construction was begun after October 20, 1985, that transports hazardous liquid; [49 CFR 195.401(c)(3)]

4. a pipeline, on which construction was begun after July 11, 1991 that transports carbon dioxide; [49 CFR 195.401(c)(4)]

5. a low-stress pipeline on which construction was begun after August 10, 1994. [49 CFR 195.401(c)(5)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2824 (December 2003), amended LR 38:105 (January 2012), LR 46:1607 (November 2020).

§30402. Procedural Manual for Operations, Maintenance, and Emergencies [49 CFR 195.402]

A. General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted. [49 CFR 195.402(a)]

B. The administrator or the state agency that has submitted a current certification under the pipeline safety laws (49 U.S.C. 60101 et seq.) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant state procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety. [49 CFR 195.402(B)]

C. Maintenance and Normal Operations. The manual required by §30402.A must include procedures for the following to provide safety during maintenance and normal operations: [49 CFR 195.402(c)]

1. making construction records, maps, and operating history available as necessary for safe operation and maintenance; [49 CFR 195.402(c)(1)]

2. gathering of data needed for reporting accidents under Chapter 301. Subchapter B in a timely and effective manner; [49 CFR 195.402(c)(2)]

3. operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this Chapter and Subchapter B of Chapter 305; [49 CFR 195.402(c)(3)]

4. determining which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned; [49 CFR 195.402(c)(4)]

5. analyzing pipeline accidents to determine their causes; [49 CFR 195.402(c)(5)]

6. minimizing the potential for hazards identified under §30402.C.4 and the possibility of recurrence of accidents analyzed under §30402.C.5; [49 CFR 195.402(c)(6)]

7. starting up and shutting down any part of the pipeline system in a manner designed to assure operation within the limits prescribed by §30406, consider the hazardous liquid or carbon dioxide in transportation, variations in altitude along the pipeline, and pressure monitoring and control devices; [49 CFR 195.402(c)(7)]

8. in the case of a pipeline that is not equipped to fail safe, monitoring from an attended location pipeline pressure

during start-up until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by §30406; [49 CFR 195.402(c)(8)]

9. in the case of facilities not equipped to fail safe that are identified under §30402.C.4 or that control receipt and delivery of the hazardous liquid or carbon dioxide, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location; [49 CFR 195.402(c)(9)]

10. abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through commercially navigable waterways the last operator of that facility must file a report upon abandonment of that facility in accordance with §30141 of this Subpart; [49 CFR 195.402(c)(10)]

11. minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under §30402.C.4 where the potential exists for the presence of flammable liquids or gases; [49 CFR 195.402(c)(11)]

12. establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each government organization that may respond to a hazardous liquid or carbon dioxide pipeline emergency and acquaint the officials with the operator’s ability in responding to a hazardous liquid or carbon dioxide pipeline emergency and means of communication; [49 CFR 195.402(c)(12)]

13. periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found; [49 CFR 195.402(c)(13)]

14. taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line. [49 CFR 195.402(c)(14)]

15. Implementing the applicable control room management procedures required by §30446. [49 CFR 195.402(c)(15)]

D. Abnormal Operation. The manual required by §30402.A must include procedures for the following to provide safety when operating design limits have been exceeded. [49 CFR 195.402(d)]

1. Responding to, investigating, and correcting the cause of: [49 CFR 195.402(d)(1)]

a. unintended closure of valves or shutdowns; [49 CFR 195.402(d)(1)(i)]

b. increase or decrease in pressure or flow rate outside normal operating limits; [49 CFR 195.402(d)(1)(ii)]

c. loss of communications; [49 CFR 195.402(d)(1)(iii)]

d. operation of any safety device; [49 CFR 195.402(d)(1)(iv)]

e. any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property. [49 CFR 195.402(d)(1)(v)]

2. Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation. [49 CFR 195.402(d)(2)]

3. Correcting variations from normal operation of pressure and flow equipment and controls. [49 CFR 195.402(d)(3)]

4. Notifying responsible operator personnel when notice of an abnormal operation is received. [49 CFR 195.402(d)(4)]

5. Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found. [49 CFR 195.402(d)(5)]

E. Emergencies. The manual required by §30402.A must include procedures for the following to provide safety when an emergency condition occurs: [49 CFR 195.402(e)]

1. receiving, identifying, and classifying notices of events which need immediate response by the operator or notice to fire, police, or other appropriate public officials and communicating this information to appropriate operator personnel for corrective action; [49 CFR 195.402(e)(1)]

2. prompt and effective response to a notice of each type of emergency, including fire or explosion occurring near or directly involving a pipeline facility, accidental release of hazardous liquid or carbon dioxide from a pipeline facility, operational failure causing a hazardous condition, and natural disaster affecting pipeline facilities; [49 CFR 195.402(e)(2)]

3. having personnel, equipment, instruments, tools, and material available as needed at the scene of an emergency; [49 CFR 195.402(e)(3)]

4. taking necessary action, such as emergency shutdown or pressure reduction, to minimize the volume of hazardous liquid or carbon dioxide that is released from any section of a pipeline system in the event of a failure; [49 CFR 195.402(e)(4)]

5. control of released hazardous liquid or carbon dioxide at an accident scene to minimize the hazards, including possible intentional ignition in the cases of flammable highly volatile liquid; [49 CFR 195.402(e)(5)]

6. minimization of public exposure to injury and probability of accidental ignition by assisting with evacuation of residents and assisting with halting traffic on

roads and railroads in the affected area, or taking other appropriate action; [49 CFR 195.402(e)(6)]

7. notifying fire, police, and other appropriate public officials of hazardous liquid or carbon dioxide pipeline emergencies and coordinating with them preplanned and actual responses during an emergency, including additional precautions necessary for an emergency involving a pipeline system transporting a highly volatile liquid; [49 CFR 195.402(e)(7)]

8. in the case of failure of a pipeline system transporting a highly volatile liquid, use of appropriate instruments to assess the extent and coverage of the vapor cloud and determine the hazardous area; [49 CFR 195.402(e)(8)]

9. providing for a post accident review of employee activities to determine whether the procedures were effective in each emergency and taking corrective action where deficiencies are found. [49 CFR 195.402(e)(9)]

10. Actions required to be taken by a controller during an emergency, in accordance with §30446. [49 CFR 195.402(e)(10)]

F. Safety-Related Condition Reports. The manual required by §30402.A must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §30133. [49 CFR 195.402(f)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2824 (December 2003), amended LR 38:106 (January 2012).

§30403. Emergency Response Training [49 CFR 195.403]

A. Each operator shall establish and conduct a continuing training program to instruct emergency response personnel to: [49 CFR 195.403(a)]

1. carry out the emergency procedures established under §30402 that relate to their assignments; [49 CFR 195.403(a)(1)]

2. know the characteristics and hazards of the hazardous liquids or carbon dioxide transported, including, in case of flammable HVL, flammability of mixtures with air, odorless vapors, and water reactions; [49 CFR 195.403(a)(2)]

3. recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquids or carbon dioxide spills, and take appropriate corrective action; [49 CFR 195.403(a)(3)]

4. take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage; and [49 CFR 195.403(a)(4)]

5. learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. [49 CFR 195.403(a)(5)]

B. At the intervals not exceeding 15 months, but at least once each calendar year, each operator shall: [49 CFR 195.403(b)]

1. review with personnel their performance in meeting the objectives of the emergency response training program set forth in Subsection A of this Section; and [49 CFR 195.403(b)(1)]

2. make appropriate changes to the emergency response training program as necessary to ensure that it is effective. [49 CFR 195.403(b)(2)]

C. Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the emergency response procedures established under §30402 for which they are responsible to ensure compliance. [49 CFR 195.403(c)]

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HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2825 (December 2003), amended LR 31:678 (March 2005).

§30404. Maps and Records [49 CFR 195.404]

A. Each operator shall maintain current maps and records of its pipeline systems that include at least the following information: [49 CFR 195.404(a)]

1. location and identification of the following pipeline facilities: [49 CFR 195.404(a)(1)]

a. breakout tanks; [49 CFR 195.404(a)(1)(i)]

b. pump stations; [49 CFR 195.404(a)(1)(ii)]

c. scraper and sphere facilities; [49 CFR 195.404(a)(1)(iii)]

d. pipeline valves; [49 CFR 195.404(a)(1)(iv)]

e. facilities to which §30402.C.9 applies; [49 CFR 195.404(a)(1)(v)]

f. rights-of-way; and [49 CFR 195.404(a)(1)(vi)]

g. safety devices to which §30428 applies; [49 CFR 195.404(a)(1)(vii)]

2. all crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines; [49 CFR 195.404(a)(2)]

3. the maximum operating pressure of each pipeline; [49 CFR 195.404(a)(3)]

4. the diameter, grade, type, and nominal wall thickness of all pipe. [49 CFR 195.404(a)(4)]

B. Each operator shall maintain for at least three years daily operating records that indicate: [49 CFR 195.404(b)]

1. the discharge pressure at each pump station; and [49 CFR 195.404(b)(1)]

2. any emergency or abnormal operation to which the procedures under §30402 apply. [49 CFR 195.404(b)(2)]

C. Each operator shall maintain the following records for the periods specified: [49 CFR 195.404(c)]

1. the date, location, and description of each repair made to pipe shall be maintained for the useful life of the pipe; [49 CFR 195.404(c)(1)]

2. the date, location, and description of each repair made to parts of the pipeline system other than pipe shall be maintained for at least one year; [49 CFR 195.404(c)(2)]

3. a record of each inspection and test required by this Chapter shall be maintained for at least two years or until the next inspection or test is performed, whichever is longer. [49 CFR 195.404(c)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2826 (December 2003).

§30405. Protection against Ignitions and Safe Access/Egress Involving Floating Roofs [49 CFR 195.405]

A. After October 2, 2000, protection provided against ignitions arising out of static electricity, lightning, and stray currents during operation and maintenance activities involving aboveground breakout tanks must be in accordance with API RP 2003 (incorporated by reference, see §30107), unless the operator notes in the procedural manual [§30402.C] why compliance with all or certain provisions of API RP 2003 is not necessary for the safety of a particular breakout tank. [49 CFR 195.405(a)]

B. The hazards associated with access/egress onto floating roofs of in-service aboveground breakout tanks to perform inspection, service, maintenance or repair activities (other than specified general considerations, specified routine tasks or entering tanks removed from service for cleaning) are addressed in API Pub 2026 (incorporated by reference, see §30107). After October 2, 2000, the operator must review and consider the potentially hazardous conditions, safety practices and procedures in API Pub 2026 for inclusion in the procedure manual [§30402.C]. [49 CFR 195.405(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2826 (December 2003), amended LR 44:1027 (June 2018).

§30406. Maximum Operating Pressure [49 CFR 195.406]

A. Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following: [49 CFR 195.406(a)]

1. the internal design pressure of the pipe determined in accordance with §30161. However, for steel pipe in pipelines being converted under §30111, if one or more factors of the design formula (§30161) are unknown, one of the following pressures is to be used as design pressure: [49 CFR 195.406(a)(1)]

a. eighty percent of the first test pressure that produces yield under section N 5.0 of appendix N of ASME/ANSI B31.8 (incorporated by reference, see §507), reduced by the appropriate factors in §30161.A and E; or [49 CFR 195.406(a)(1)(i)]

b. if the pipe is 12-3/4 in. (324 mm.) or less outside diameter and is not tested to yield under this Paragraph, 200 p.s.i. (1379 kPa) gage; [49 CFR 195.406(a)(1)(ii)]

2. the design pressure of any other component of the pipeline; [49 CFR 195.406(a)(2)]

3. eighty percent of the test pressure for any part of the pipeline which has been pressure tested under Chapter 303; [49 CFR 195.406(a)(3)]

4. eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is excepted from testing under §30305; [49 CFR 195.406(a)(4)]

5. for pipelines under §30302.B.1 and B.2.a that have not been pressure tested under Chapter 303 of this Subpart, 80 percent of the test pressure or highest operating pressure to which the pipeline was subjected for four or more continuous hours that can be demonstrated by recording charts or logs made at the time the test or operations were conducted. [49 CFR 195.406(a)(5)]

B. No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under §30406.A. Each operator must provide adequate controls and protective equipment to control the pressure within this limit. [49 CFR 195.406(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2826 (December 2003), amended LR 44:1027 (June 2018).

§30408. Communications [49 CFR 195.408]

A. Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system. [49 CFR 195.408(a)]

B. The communication system required by §30408.A must, as a minimum, include means for: [49 CFR 195.408(b)]

1. monitoring operational data as required by §30402.C.9; [49 CFR 195.408(b)(1)]

2. receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and sending this information to appropriate

personnel or government agencies for corrective action; [49 CFR 195.408(b)(2)]

3. conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies; and [49 CFR 195.408(b)(3)]

4. providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster. [49 CFR 195.408(b)(4)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2827 (December 2003).

§30410. Line Markers [49 CFR 195.410]

A. Except as provided in §30410.B, each operator shall place and maintain line markers over each buried pipeline in accordance with the following: [49 CFR 195.410(a)]

1. markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known; [49 CFR 195.410(a)(1)]

2. the marker must state at least the following on a background of sharply contrasting color: [49 CFR 195.410(a)(2)]

a. the word “warning,” “caution,” or “danger” followed by the word “petroleum (or the name of the hazardous liquid transported) pipeline”, or “carbon dioxide pipeline,” all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with an approximate stroke of 1/4 inch (6.4 millimeters); [49 CFR 195.410(a)(2)(i)]

b. the name of the operator and a telephone number (including area code) where the operator can be reached at all times. [49 CFR 195.410(a)(2)(ii)]

B. Line markers are not required for buried pipelines located: [49 CFR 195.410(b)]

1. offshore or at crossings of or under waterways and other bodies of water; or [49 CFR 195.410(b)(1)]

2. in heavily developed urban areas such as downtown business centers where: [49 CFR 195.410(b)(2)]

a. the placement of markers is impracticable and would not serve the purpose for which markers are intended; and [49 CFR 195.410(b)(2)(i)]

b. the local government maintains current substructure records. [49 CFR 195.410(b)(2)(ii)]

C. Each operator shall provide line marking at locations where the line is above ground in areas that are accessible to the public. [49 CFR 195.410(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2827 (December 2003).

§30412. Inspection of Rights-of-Way and Crossings under Navigable Waters [49 CFR 195.412]

A. Each operator shall, at intervals not exceeding three weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate means of traversing the right-of-way. [49 CFR 195.412(a)]

B. Except for offshore pipelines, each operator shall, at intervals not exceeding five years, inspect each crossing under a navigable waterway to determine the condition of the crossing. [49 CFR 195.412(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2827 (December 2003).

§30413. Underwater Inspection and Reburial of Pipelines in the Gulf of Mexico and Its Inlet [49 CFR 195.413]

A. Except for gathering lines of 4 1/2 inches (114 mm) nominal outside diameter or smaller, each operator shall prepare and follow a procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. The procedures must be in effect August 10, 2005. [49 CFR 195.413(a)]

B. Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. [49 CFR 195.413(b)]

C. If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall: [49 CFR 195.413(c)]

1. promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802, as well as Louisiana Pipeline Safety (225) 342-5505, (day or night), of the location and, if available, the geographic coordinates of that pipeline; [49 CFR 195.413(c)(1)]

2. promptly, but not later than seven days after discovery, mark the location of the pipeline in accordance with 33 CFR Part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and [49 CFR 195.413(c)(2)]

3. within six months after discovery, or not later than November 1 of the following year if the six month period is later than November 1 of the year of discovery, bury the pipeline so that the top of the pipe is 36 inches

(914 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) for normal excavation or 18 inches (457 millimeters) for rock excavation: [49 CFR 195.413(c)(3)]

a. an operator may employ engineered alternatives to burial that meet or exceed the level of protection provided by burial; [49 CFR 195.413(c)(3)(i)]

b. if an operator cannot obtain required state or Federal permits in time to comply with this Section, it must notify OPS; specify whether the required permit is state or Federal; and, justify the delay. [49 CFR 195.413(c)(3)(ii)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2827 (December 2003), amended LR 31:678 (March 2005).

§30414. Inspections of Pipelines in Areas Affected by Extreme Weather and Natural Disasters [49 CFR 195.414]

A. General. Following an extreme weather event or natural disaster that has the likelihood of damage to infrastructure by the scouring or movement of the soil surrounding the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.. [49 CFR 195.414(a)]

B. Inspection Method. An operator must consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under Subsection A of this Section. [49 CFR 195.414(b)]

C. Time Period. The inspection required under Subsection A of this Section must commence within 72 hours after the cessation of the event, defined as the point in time when the affected area can be safely accessed by the personnel and equipment required to perform the inspection as determined under Subsection B of this Section. In the event that the operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director and Office of Conservation Pipeline Division for intrastate facilities as soon as practicable. [49 CFR 195.414(c)]

D. Remedial Action. An operator must take prompt and appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required under Subsection A of this Section. Such actions might include, but are not limited to: [49 CFR 195.414(d)]

1. reducing the operating pressure or shutting down the pipeline; [49 CFR 195.414(d)(1)]

2. for each pipeline constructed on Modifying, repairing, or replacing any damaged pipeline facilities; [49 CFR 195.414(d)(2)]

3. preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way; [49 CFR 195.414(d)(3)]

4. performing additional patrols, surveys, tests, or inspections; [49 CFR 195.414(d)(4)]

5. implementing emergency response activities with federal, state, or local personnel; and [49 CFR 195.414(d)(5)]

6. notifying affected communities of the steps that can be taken to ensure public safety. [49 CFR 195.414(d)(6)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 46:1607 (November 2020).

§30416. Pipeline Assessments [49 CFR 195.416]

A. Scope. This section applies to onshore line pipe that can accommodate inspection by means of in-line inspection tools and is not subject to the integrity management requirements in § 30452. [49 CFR 195.416(a)]

B. General. An operator must perform an initial assessment of each of its pipeline segments by October 1, 2029, and perform periodic assessments of its pipeline segments at least once every 10 calendar years from the year of the prior assessment or as otherwise necessary to ensure public safety or the protection of the environment. [49 CFR 195.416(b)]

C. Method. Except as specified in Subsection D of this Section, an operator must perform the integrity assessment for the range of relevant threats to the pipeline segment by the use of an appropriate in-line inspection tool(s). When performing an assessment using an in-line inspection tool, an operator must comply with §30591. An operator must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or other equivalent methods for determining uncertainties) in identifying anomalies. If this is impracticable based on operational limits, including operating pressure, low flow, and pipeline length or availability of in-line inspection tool technology for the pipe diameter, then the operator must perform the assessment using the appropriate method(s) in Paragraphs C.1, C.2, or C.3 of this Section for the range of relevant threats being assessed. The methods an operator selects to assess low-frequency electric resistance welded pipe, pipe with a seam factor less than 1.0 as defined in § 30161.E or lap-welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity, cracking, and of detecting corrosion and deformation anomalies. The following alternative assessment methods may be used as specified in this Subsection: [49 CFR 195.416(c)]

1. a pressure test conducted in accordance with Chapter 303 of this Part; [49 CFR 195.416(c)(1)]

2. external corrosion direct assessment in accordance with §30588; or [49 CFR 195.416(c)(2)]

3. other technology in accordance with Subsection D. [49 CFR 195.416(c)(3)]

D. Other Technology

1. Operators may elect to use other technologies if the operator can demonstrate the technology can provide an equivalent understanding of the condition of the line pipe for threat being assessed. An operator choosing this option must notify the Office of Pipeline Safety (OPS) and the Office of Conservation for intrastate jurisdictional facilities 90 days before conducting the assessment by: [49 CFR 195.416(d)]

a. sending the notification, along with the information required to demonstrate compliance with this Paragraph, to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590 and Office of Conservation – Pipeline Division, P.O. Box 94275, Baton Rouge, LA 70804-9275; or [49 CFR 195.416(d)(1)]

b. sending the notification, along with the information required to demonstrate compliance with this Paragraph, to the Information Resources Manager by facsimile to (202) 366-7128 and pipelineinspectors@la.gov. [49 CFR 195.416(d)(2)]

2. Prior to conducting the "other technology" assessments, the operator must receive a notice of "no objection" from the PHMSA Information Services Manager or Designee and the Office of Conservation. [49 CFR 195.416(d)(3)]

E. Data Analysis. A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under Subsection B of this Section to determine if a condition could adversely affect the safe operation of the pipeline. Operators must consider uncertainties in any reported results (including tool tolerance) as part of that analysis. [49 CFR 195.416(e)]

F. Discovery of Condition. For purposes of §30401.B.1, discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination required under Subsection E of this Section, unless the operator can demonstrate the 180-day interval is impracticable. If the operator believes that 180 days are impracticable to make a determination about a condition found during an assessment, the pipeline operator must notify PHMSA and provide an expected date when adequate information will become available. This notification must be made in accordance with §30452.M. [49 CFR 195.416(f)]

G. Remediation. An operator must comply with the requirements in §30401 if a condition that could adversely affect the safe operation of a pipeline is discovered in complying with Subsection E and F of this Section. [49 CFR 195.416(g)]

H. Consideration of Information. An operator must consider all relevant information about a pipeline in complying with the requirements in Subsection A through G of this Section. [49 CFR 195.416(h)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 46:1607 (November 2020), repromulgated LR. 47:1148 (August 2021).

§30420. Valve Maintenance [49 CFR 195.420]

A. Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times. [49 CFR 195.420(a)]

B. Each operator shall, at intervals not exceeding seven and one-half months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly. [49 CFR 195.420(b)]

C. Each operator shall provide protection for each valve from unauthorized operation and from vandalism. [49 CFR 195.420(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2828 (December 2003).

§30422. Pipeline Repairs [49 CFR 195.422]

A. Each operator shall, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons or property. [49 CFR 195.422(a)]

B. No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this Subpart. [49 CFR 195.422(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2828 (December 2003).

§30424. Pipe Movement [49 CFR 195.424]

A. No operator may move any line pipe, unless the pressure in the line section involved is reduced to not more than 50 percent of the maximum operating pressure. [49 CFR 195.424(a)]

B. No operator may move any pipeline containing highly volatile liquids where materials in the line section involved are joined by welding unless: [49 CFR 195.424(b)]

1. movement when the pipeline does not contain highly volatile liquids is impractical; [49 CFR 195.424(b)(1)]

2. the procedures of the operator under §30402 contain precautions to protect the public against the hazard in moving pipelines containing highly volatile liquids, including the use of warnings, where necessary, to evacuate the area close to the pipeline; and [49 CFR 195.424(b)(2)]

3. the pressure in that line section is reduced to the lower of the following: [49 CFR 195.424(b)(3)]

a. fifty percent or less of the maximum operating pressure; or [49 CFR 195.424(b)(3)(i)]

b. the lowest practical level that will maintain the highly volatile liquid in a liquid state with continuous flow, but not less than 50 p.s.i. (345 kPa) gage above the vapor pressure of the commodity. [49 CFR 195.424(b)(3)(ii)]

C. No operator may move any pipeline containing highly volatile liquids where materials in the line section involved are not joined by welding unless: [49 CFR 195.424(c)]

1. the operator complies with §30424.B.1 and §30424.B.2; and [49 CFR 195.424(c)(1)]

2. that line section is isolated to prevent the flow of highly volatile liquid. [49 CFR 195.424(c)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2828 (December 2003).

§30426. Scraper and Sphere Facilities [49 CFR 195.426]

A. No operator may use a launcher or receiver that is not equipped with a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. The operator must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent insertion or removal of scrapers or spheres if pressure has not been relieved in the barrel. [49 CFR 195.426]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2828 (December 2003).

§30428. Overpressure Safety Devices and Overfill Protection Systems [49 CFR 195.428]

A. Except as provided in §30428.B, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed seven and one-half months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used. [49 CFR 195.428(a)]

B. In the case of relief valves on pressure breakout tanks containing highly volatile liquids, each operator shall test each valve at intervals not exceeding five years. [49 CFR 195.428(b)]

C. Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to Section 7.1.2 of API Standard 2510. Other aboveground breakout tanks with 600 gallons (2271 liters) or more of storage capacity that are constructed or significantly altered after October 2, 2000, must have an overfill protection system installed according to API Recommended Practice 2350 (incorporated by reference, see §30107). However, operators need not comply with any part of API Recommended Practice 2350 for a particular breakout tank if the operator notes in the manual required by §30402 why compliance with that part is not necessary for safety of the tank. [49 CFR 195.428(c)]

D. After October 2, 2000, the requirements of §30428 A and B for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems. [49 CFR 195.428(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2828 (December 2003), amended LR 44:1028 (June 2018).

§30430. Firefighting Equipment [49 CFR 195.430]

A. Each operator shall maintain adequate firefighting equipment at each pump station and breakout tank area. The equipment must be: [49 CFR 195.430]

1. in proper operating condition at all times; [49 CFR 195.430(a)]

2. plainly marked so that its identity as firefighting equipment is clear; and [49 CFR 195.430(b)]

3. located so that it is easily accessible during a fire. [49 CFR 195.430(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2829 (December 2003).

§30432. Inspection of In-Service Breakout Tanks [49 CFR 195.432]

A. Except for breakout tanks inspected under §30432 B and C, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank. [49 CFR 195.432(a)]

B. Each operator must inspect the physical integrity of in-service atmospheric and low-pressure steel above-ground breakout tanks according to API Std 653 (except section 6.4.3, Alternative Internal Inspection Interval) (incorporated by reference, see §30107). However, if structural conditions prevent access to the tank bottom, its integrity may be assessed according to a plan included in the operations and maintenance manual under 30402.C.3. The risk-based internal inspection procedures in API Std 653, section 6.4.3 cannot be used to determine the internal inspection interval. [49 CFR 195.432(b)]

1. operators who established internal inspection intervals based on risk-based inspection procedures prior to March 6, 2015 must re-establish internal inspection intervals based on API Std 653, section 6.4.2 (incorporated by reference, *s*ee §30107). [49 CFR 195.432(b)(1)]

a. if the internal inspection interval was determined by the prior risk-based inspection procedure using API Std 653, section 6.4.3 and the resulting calculation exceeded 20 years, and it has been more than 20 years since an internal inspection was performed, the operator must complete a new internal inspection in accordance with §30402.B.1 by January 5, 2017. [49 CFR 195.432(b)(1)(i)]

b. if the internal inspection interval was determined by the prior risk-based inspection procedure using API Std 653, section 6.4.3 and the resulting calculation was less than or equal to 20 years, and the time since the most recent internal inspection exceeds the re-established inspection interval in accordance with §30402.B.1, the operator must complete a new internal inspection by January 5, 2017. [49 CFR 195.432(b)(1)(ii)]

c. if the internal inspection interval was not based upon current engineering and operational information (i.e., actual corrosion rate of floor plates, actual remaining thickness of the floor plates, etc.), the operator must complete a new internal inspection by January 5, 2017 and re-establish a new internal inspection interval in accordance with §30402.B.1. [49 CFR 195.432(b)(1)(iii)]

C. Each operator must inspect the physical integrity of in-service steel aboveground breakout tanks built to API Std 2510 (incorporated by reference, see §30107) according to Section 6 of API Std 510 (incorporated by reference, see §30107). [49 CFR 195.432(c)]

D. The intervals of inspection specified by documents referenced in §30432 B and C begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier. [49 CFR 195.432(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2829 (December 2003), amended LR 38:106 (January 2012), LR 44:1028 (June 2018).

§30434. Signs [49 CFR 195.434]

A. Each operator must maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. [49 CFR 195.434]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2829 (December 2003), amended LR 31:679 (March 2005), LR 35:2797 (December 2009).

§30436. Security of Facilities [49 CFR 195.436]

A. Each operator shall provide protection for each pumping station and breakout tank area and other exposed facility (such as scraper traps) from vandalism and unauthorized entry. [49 CFR 195.436]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2829 (December 2003).

§30438. Smoking or Open Flames [49 CFR 195.438]

A. Each operator shall prohibit smoking and open flames in each pump station area and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors. [49 CFR 195.438]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2829 (December 2003).

§30440. Public Awareness [49 CFR 195.440]

A. Each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference, see §30107). [49 CFR 195.440(a)]

B. The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities, except as stated in Paragraph B.1. [49 CFR 195.440(b)]

1. Regulatory inspections are not an acceptable alternative to conducting an annual audit for measuring program implementation as mentioned in API RP 1162 section 8.3.

C. The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety. [49 CFR 195.440(c)]

D. The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: [49 CFR 195.440(d)]

1. use of a one-call notification system prior to excavation and other damage prevention activities; [49 CFR 195.440(d)(1)]

2. possible hazards associated with unintended releases from a hazardous liquid or carbon dioxide pipeline facility; [49 CFR 195.440(d)(2)]

3. physical indications that such a release may have occurred; [49 CFR 195.440(d)(3)]

4. steps that should be taken for public safety in the event of a hazardous liquid or carbon dioxide pipeline release; and [49 CFR 195.440(d)(4)]

5. procedures to report such an event. [49 CFR 195.440(d)(5)]

E. The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations. [49 CFR 195.440(e)]

F. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports hazardous liquid or carbon dioxide. [49 CFR 195.440(f)]

G. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area. [49 CFR 195.440(g)]

H. Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate state agency. [49 CFR 195.440(h)]

I. The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies. [49 CFR 195.440(i)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2829 (December 2003), amended LR 33:470 (March 2007), LR 35:2797 (December 2009), LR 38:106 (January 2012), LR 44:1028 (June 2018).

§30442. Damage Prevention Program [49 CFR 195.442]

A. Except as provided in §30442.D, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the 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. [49 CFR 195.442(a)]

B. An operator may comply with any of the requirements of §30442.C through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of the responsibility for compliance with this section. However, an operator must perform the duties of Subsection 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 the Section, a one-call system is considered a *qualified one-call system* if it meets the requirements of §30442.B.1 or B.2. [49 CFR 195.442(b)]

1. The state has adopted a one-call damage prevention program under 49 CFR 198.37; or [49 CFR 195.442(b)(1)]

2. the one-call system: [49 CFR 195.442(b)(2)]

a. is operated in accordance with 49 CFR 198.39; [49 CFR 195.442(b)(2)(i)]

b. provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and [49 CFR 195.442(b)(2)(ii)]

c. 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. [49 CFR 195.442(b)(2)(iii)]

C. The damage prevention program required by §30442.A. must, at a minimum: [49 CFR 195.442(c)]

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; [49 CFR 195.442(c)(1)]

2. provide for notification of the public in the vicinity of the pipeline and actual notification of persons identified in §30442.C.1 of the following as often as needed to make them aware of the damage prevention program: [49 CFR 195.442(c)(2)]

a. the program's existence and purpose; and [49 CFR 195.442(c)(2)(i)]

b. how to learn the location of underground pipelines before excavation activities are begun; [49 CFR 195.442(c)(2)(ii)]

3. provide a means of receiving and recording notification of planned excavation activities; [49 CFR 195.442(c)(3)]

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; [49 CFR 195.442(c)(4)]

5. provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins; [49 CFR 195.442(c)(5)]

6. provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities: [49 CFR 195.442(c)(6)]

a. the inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and [49 CFR 195.442(c)(6)(i)]

b. in the case of blasting, any inspection must include leakage surveys. [49 CFR 195.442(c)(6)(ii)]

D. A damage prevention program under this Section is not required for the following pipelines: [49 CFR 195.442(d)]

1. pipelines located offshore; [49 CFR 195.442(d)(1)]

2. pipelines to which access is physically controlled by the operator. [49 CFR 195.442(d)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2829 (December 2003), amended LR 35:2797 (December 2009).

§30444. Leak Detection [49 CFR 195.444]

A. Scope. Except for offshore gathering and regulated rural gathering pipelines, this section applies to all hazardous liquid pipelines transporting liquid in single phase (without gas in the liquid). [49 CFR 195.444(a)]

B. General. A pipeline must have an effective system for detecting leaks in accordance with §§30134 or 30452, as appropriate. An operator must evaluate the capability of its leak detection system to protect the public, property, and the environment and modify it as necessary to do so. At a minimum, an operator's evaluation must consider the following factors - length and size of the pipeline, type of product carried, the swiftness of leak detection, location of nearest response personnel, and leak history. [49 CFR 195.444(b)]

C. CPM Leak Detection Systems. Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline must comply with API RP 1130 (incorporated by reference, see §30107) in operating, maintaining, testing, record keeping, and dispatcher training of the system. [49 CFR 195.444(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2830 (December 2003), amended LR 44:1028 (June 2018), LR 46:1608 (November 2020).

§30446. Control Room Management [49 CFR 195.446]

A. General. This Section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this Section. The procedures required by this Section must be integrated, as appropriate, with the operator’s written procedures required by §30402. An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by Subsections and Paragraphs B, C.5, D.2, D.3, F and G of this Section must be implemented no later than October 1, 2011. The procedures required by Paragraphs C.1 through C.4, D.1, D.4, and E must be implemented no later than August 1, 2012. The training procedures required by Subsection H must be implemented no later than August 1, 2012, except that any training required by another Paragraph of this Section must be implemented no later than the deadline for that Paragraph. [49 CFR 195.446(a)]

B. Roles and Responsibilities. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller’s prompt and appropriate response to operating conditions, an operator must define each of the following: [49 CFR 195.446(b)]

1. a controller’s authority and responsibility to make decisions and take actions during normal operations; [49 CFR 195.446(b)(1)]

2. a controller’s role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller’s responsibility to take specific actions and to communicate with others; [49 CFR 195.446(b)(2)]

3. a controller’s role during an emergency, even if the controller is not the first to detect the emergency, including the controller’s responsibility to take specific actions and to communicate with others; [49 CFR 195.446(b)(3)]

4. a method of recording controller shift-changes and any hand-over of responsibility between controllers; and [49 CFR 195.446(b)(4)]

5. The roles, responsibilities and qualifications of others who have the authority to direct or supersede the specific technical actions of controllers. [49 CFR 195.446(b)(5)]

C. Provide Adequate Information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following: [49 CFR 195.446(c)]

1. implement API RP 1165 (incorporated by reference, see §30107) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of API RP 1165 are not practical for the SCADA system used; [49 CFR 195.446(c)(1)]

2. conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays; [49 CFR 195.446(c)(2)]

3. test and verify an internal communication plan to provide adequate means for manual operation of the pipeline

safely, at least once each calendar year, but at intervals not to exceed 15 months; [49 CFR 195.446(c)(3)]

4. test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and [49 CFR 195.446(c)(4)]

5. implement Section 5 of API RP 1168 (incorporated by reference, see §30107) to establish procedures for when a different controller assumes responsibility, including the content of information to be exchanged. [49 CFR 195.446(c)(5)]

D. Fatigue Mitigation. Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined: [49 CFR 195.446(d)]

1. establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep; [49 CFR 195.446(d)(1)]

2. educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue; [49 CFR 195.446(d)(2)]

3. train controllers and supervisors to recognize the effects of fatigue; and [49 CFR 195.446(d)(3)]

4. establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility. [49 CFR 195.446(d)(4)]

E. Alarm Management. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to: [49 CFR 195.446(e)]

1. review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations; [49 CFR 195.446(e)(1)]

2. identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities; [49 CFR 195.446(e)(2)]

3. verify the correct safety-related alarm set-point values and alarm descriptions when associated field instruments are calibrated or changed and at least once each calendar year, but at intervals not to exceed 15 months; [49 CFR 195.446(e)(3)]

4. review the alarm management plan required by this subsection at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan; [49 CFR 195.446(e)(4)]

5. monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not exceeding 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and [49 CFR 195.446(e)(5)]

6. address deficiencies identified through the implementation of Paragraphs E.1 through E.5 of this Section. [49 CFR 195.446(e)(6)]

F. Change Management. Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following: [49 CFR 195.446(f)]

1. implement Section 7 of API RP 1168 (incorporated by reference, see §30107) for control room management change and require coordination between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration; and [49 CFR 195.446(f)(1)]

2. require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations. [49 CFR 195.446(f)(2)]

G. Operating Experience. Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following. [49 CFR 195.446(g)]

1. Review accidents that must be reported pursuant to §30125 and 30127 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to: [49 CFR 195.446(g)(1)]

a. controller fatigue; [49 CFR 195.446(g)(1)(i)]

b. field equipment; [49 CFR 195.446(g)(1)(ii)]

c. the operation of any relief device; [49 CFR 195.446(g)(1)(iii)]

d. procedures; [49 CFR 195.446(g)(1)(iv)]

e. SCADA system configuration; and [49 CFR 195.446(g)(1)(v)]

f. SCADA system performance. [49 CFR 195.446(g)(1)(vi)]

2. Include lessons learned from the operator's experience in the training program required by this Section. [49 CFR 195.446(g)(2)]

H. Training. Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements: [49 CFR 195.446(h)]

1. responding to abnormal operating conditions likely to occur simultaneously or in sequence; [49 CFR 195.446(h)(1)]

2. use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions; [49 CFR 195.446(h)(2)]

3. training controllers on their responsibilities for communication under the operator's emergency response procedures; [49 CFR 195.446(h)(3)]

4. training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; [49 CFR 195.446(h)(4)]

5. for pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application; and [49 CFR 195.446(h)(5)]

6. control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations. Operators must comply with the team training requirements under this Paragraph no later than January 23, 2018. [49 CFR 195.446(h)(6)]

I. Compliance Validation. Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a state, to the appropriate state agency. [49 CFR 195.446(i)]

J. Compliance and Deviations. An operator must maintain for review during inspection: [49 CFR 195.446(j)]

1. records that demonstrate compliance with the requirements of this Section; and [49 CFR 195.446(j)(1)]

2. documentation to demonstrate that any deviation from the procedures required by this Section was necessary for the safe operation of the pipeline facility. [49 CFR 195.446(j)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 38:106 (January 2012), amended LR 44:1028 (June 2018).

§30450. High Consequence Areas—Definitions [49 CFR Part 195.450]

A. The following definitions apply to this Section and §30452.

Emergency Flow Restricting Device or EFRD—a check valve or remote control valve as follows:

a. *Check Valve*—a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction;

b. *Remote Control Valve* or *RCV*—any valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.

High Consequence Area—

a. *Commercially Navigable Waterway*—a waterway where a substantial likelihood of commercial navigation exists;

b. *High Population Area*—an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;

c. *Other Populated Area*—a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area;

d. *Unusually Sensitive Area*—as defined in §30112.

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HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2830 (December 2003).

§30452. Pipeline Integrity Management in High Consequence Areas [49 CFR 195.452]

A. Which pipelines are covered by this Section? This Section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. (§30905, Appendix C of this Subpart provides guidance on determining if a pipeline could affect a high consequence area.) Covered pipelines are categorized as follows. [49 CFR 195.452(a)]

1. Category 1 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to this Subpart. [49 CFR 195.452(a)(1)]

2. Category 2 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to this Subpart. [49 CFR 195.452(a)(2)]

3. Category 3 includes pipelines constructed or converted after May 29, 2001, and low-stress pipelines in rural areas under §30118. [49 CFR 195.452(a)(3)]

4. Low stress pipelines as specified in § 30118. [49 CFR 195.452(a)(4)]

B. What program and practices must operators use to manage pipeline integrity? Each operator of a pipeline covered by this Section must: [49 CFR 195.452(b)]

1. develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: [49 CFR 195.452(b)(1)]

Pipeline	Date
Category 1	March 31, 2002
Category 2	February 18, 2003
Category 3	Date the pipeline begins operation or as provided in §30118 for low stress pipelines in rural areas.

2. include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: [49 CFR 195.452(b)(2)]

Pipeline	Date
Category 1	December 31, 2001
Category 2	November 18, 2002
Category 3	Date the pipeline begins operation

3. include in the program a plan to carry out baseline assessments of line pipe as required by Subsection C of this Section; [49 CFR 195.452(b)(3)]

4. include in the program a framework that:[49 CFR 195.452(b)(4)]

a. addresses each element of the integrity management program under Subsection F of this Section, including continual integrity assessment and evaluation under Subsection J of this Section; and [49 CFR 195.452(b)(4)(i)]

b. initially indicates how decisions will be made to implement each element; [49 CFR 195.452(b)(4)(ii)]

5. implement and follow the program; [49 CFR 195.452(b)(5)]

6. follow recognized industry practices in carrying out this section, unless:[49 CFR 195.452(b)(6)]

a. this Section specifies otherwise; or [49 CFR 195.452(b)(6)(i)]

b. the operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection. [49 CFR 195.452(b)(6)(ii)]

C. What must be in the baseline assessment plan? [49 CFR 195.452(c)]

1. An operator must include each of the following elements in its written baseline assessment plan. [49 CFR 195.452(c)(1)]

a. The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by in-line inspection tool(s) described in Subclause C.1.a.i this Section for the range of relevant threats to the pipeline segment. If it is impracticable based upon the construction of the pipeline (e.g., diameter changes, sharp bends, and elbows) or operational limits including operating pressure, low flow, pipeline length, or availability of in-line inspection tool technology for the pipe diameter, then the operator must use the appropriate method(s) in Subclause C.1.a.ii, iii, or iv of this Section for the range of relevant threats to the pipeline segment. The methods an operator selects to assess low-frequency electric resistance welded pipe, pipe with a seam factor less than 1.0 as defined in §30161.E or lap-welded pipe susceptible to longitudinal seam failure, must be capable of assessing seam integrity, cracking, and of detecting corrosion and deformation anomalies. [49 CFR 195.452(c)(1)(i)]

i. In-line inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges, and grooves. For pipeline segments with an identified or probable risk or threat related to cracks (such as at pipe body or weld seams) based on the risk factors specified in Subsection E, an operator must use an in-line inspection tool or tools capable of detecting crack anomalies. When performing an assessment using an in- line inspection tool, an operator must comply with §30591. An operator using this method must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or equivalent for determining uncertainties) in identifying anomalies; [49 CFR 195.452(c)(1)(i)(A)]

ii. pressure test conducted in accordance with Chapter 303. of this Subpart; [49 CFR 195.452 (c)(1)(i)(B)]

iii. external corrosion direct assessment in accordance with §30588; or [49 CFR 195.452(c)(1)(i)(C)]

iv. other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the addresses or facsimile numbers specified in Subsection M of this Section [49 CFR 195.452(c)(1)(i)(D)].

b. a schedule for completing the integrity assessment; [49 CFR 195.452(c)(1)(ii)]

c. an explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule; [49 CFR 195.452(c)(1)(iii)]

2. an operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification. [49 CFR 195.452(c)(2)]

D. When must operators complete baseline assessments? [49 CFR 195.452(d)]

1. All Pipelines. An operator must complete the baseline assessment before a new or conversion-to-service pipeline begins operation through the development of procedures, identification of high consequence areas, and pressure testing of could- affect high consequence areas in accordance with §30304. [49 CFR 195.452(d)(1)]

2. Newly Identified Areas. If an operator obtains information (whether from the information analysis required under Subsection G of this section, Census Bureau maps, or

any other source) demonstrating that the area around a pipeline segment has changed to meet the definition of a high consequence area (see §30450), that area must be incorporated into the operator's baseline assessment plan within one year from the date that the information is obtained. An operator must complete the baseline assessment of any pipeline segment that could affect a newly identified high consequence area within 5 years from the date an operator identifies the area. [49 CFR 195.452(d)(2)]

Pipeline	Date
Category 1	January 1, 1996
Category 2	February 15, 1997

E. What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? [49 CFR 195.452(e)]

1. An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see Paragraphs D.1 and J.3 of this Section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to: [49 CFR 195.452(e)(1)]

a. results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate; [49 CFR 195.452(e)(1)(i)]

b. pipe size, material, manufacturing information, coating type and condition, and seam type; [49 CFR 195.452(e)(1)(ii)]

c. leak history, repair history and cathodic protection history; [49 CFR 195.452(e)(1)(iii)]

d. product transported; [49 CFR 195.452(e)(1)(iv)]

e. operating stress level; [49 CFR 195.452(e)(1)(v)]

f. existing or projected activities in the area; [49 CFR 195.452(e)(1)(vi)]

g. local environmental factors that could affect the pipeline (e.g., seismicity, corrosivity of soil, subsidence, climatic); [49 CFR 195.452(e)(1)(vii)]

h. geo-technical hazards; and [49 CFR 195.452(e)(1)(viii)]

i. physical support of the segment such as by a cable suspension bridge. [49 CFR 195.452(e)(1)(ix)]

2. Section 30905, Appendix C, of this Subpart provides further guidance on risk factors. [49 CFR 195.452(e)(2)]

F. What are the elements of an integrity management program? An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program: [49 CFR 195.452(f)]

1. a process for identifying which pipeline segments could affect a high consequence area; [49 CFR 195.452(f)(1)]

2. a baseline assessment plan meeting the requirements of Subsection C of this Section; [49 CFR 195.452(f)(2)]

3. an analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see Subsection G of this Section); [49 CFR 195.452(f)(3)]

4. criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see Subsection H of this Section); [49 CFR 195.452(f)(4)]

5. a continual process of assessment and evaluation to maintain a pipeline’s integrity (see Subsection J of this Section); [49 CFR 195.452(f)(5)]

6. identification of preventive and mitigative measures to protect the high consequence area (see Subsection I of this Section); [49 CFR 195.452(f)(6)]

7. methods to measure the program’s effectiveness (see Subsection K of this Section); [49 CFR 195.452(f)(7)]

8. a process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see Subsection H.2 of this Section). [49 CFR 195.452(f)(8)]

9. procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to Office of Conservation, Pipeline Division for intrastate jurisdictional facilities.

G. What is an information analysis? In periodically evaluating the integrity of each pipeline segment (see Subsection J of this Section), an operator must analyze all available information about the integrity of its entire pipeline and the consequences of a possible failure along the pipeline. Operators must continue to comply with the data integration elements specified in §30452.G that were in effect on October 1, 2018, until October 1, 2022. Operators must begin to integrate all the data elements specified in this section starting October 1, 2020, with all attributes integrated by October 1, 2022. This analysis must: [49 CFR 195.452(g)]

1. integrate information and attributes about the pipeline that include, but are not limited to: [49 CFR 195.452(g)(1)]

a. pipe diameter, wall thickness, grade, and seam type; [49 CFR 195.452(g)(1)(i)]

b. pipe coating, including girth weld coating; [49 CFR 195.452(g)(1)(ii)]

c. maximum operating pressure (MOP) and temperature; [49 CFR 195.452(g)(1)(iii)]

d. endpoints of segments that could affect high consequence areas (HCAs); [49 CFR 195.452(g)(1)(iv)]

e. hydrostatic test pressure including any test failures or leaks, if known; [49 CFR 195.452(g)(1)(v)]

f. location of casings and if shorted; [49 CFR 195.452(g)(1)(vi)]

g. any in-service ruptures or leaks, including identified causes; [49 CFR 195.452(g)(1)(vii)]

h. data gathered through integrity assessments required under this Section; [49 CFR 195.452(g)(1)(viii)]

i. close interval survey (CIS) survey results; [49 CFR 195.452(g)(1)(ix)]

j. depth of cover surveys; [49 CFR 195.452(g)(1)(x)]

k. corrosion protection (CP) rectifier readings; [49 CFR 195.452(g)(1)(xi)]

l. CP test point survey readings and locations; [49 CFR 195.452(g)(1)(xii)]

m. AC/DC and foreign structure interference surveys; [49 CFR 195.452(g)(1)(xiii)]

n. pipe coating surveys and cathodic protection surveys. [49 CFR 195.452(g)(1)(xiv)]

o. results of examinations of exposed portions of buried pipelines (i.e., pipe and pipe coating condition, see §30569; [49 CFR 195.452(g)(1)(xv)]

p. stress corrosion cracking (SCC) and other cracking (pipe body or weld) excavations and findings, including in- situ non-destructive examinations and analysis results for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipeline; [49 CFR 195.452(g)(1)(xvi)]

q. aerial photography; [49 CFR 195.452(g)(1)(xvii)]

r. location of foreign line crossings; [49 CFR 195.452(g)(1)(xviii)]

s. pipe exposures resulting from repairs and encroachments; [49 CFR 195.452(g)(1)(xix)]

t. seismicity of the area; and [49 CFR 195.452(g)(1)(xx)]

u. other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this Part; [49 CFR 195.452(g)(1)(xxi)]

2. consider information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline; [49 CFR 195.452(g)(2)]

3. consider how a potential failure would affect high consequence areas, such as location of a water intake; [49 CFR 195.452(g)(3)]

4. identify spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings; evidence of pipeline damage where aerial photography shows evidence of encroachment). Storing the information in a geographic information system (GIS), alone, is not sufficient. An operator must analyze for interrelationships among the data. [49 CFR 195.452(g)(4)]

H. What actions must an operator take to address integrity issues? [49 CFR 195.452(h)]

1. General Requirements. An operator must take prompt action to address all anomalous conditions in the pipeline that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity, as required by this part. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with all other applicable requirements in this part in remediating a condition. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe and timely manner and are made so as to prevent damage to persons, property, or the environment. The calculation method(s) used for anomaly evaluation must be applicable for the range of relevant threats. [49 CFR 195.452(h)(1)]

a. Temporary Pressure Reduction. An operator must notify PHMSA, in accordance with Subsection M of this section, if the operator cannot meet the schedule for evaluation and remediation required under Paragraph H.3 of this section and cannot provide safety through a temporary reduction in operating pressure. [49 CFR 195.452(h)(1)(i)]

b. Long-Term Pressure Reduction. When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with Subsection M of this section and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline. [49 CFR 195.452(h)(1)(ii)]

2. Discovery of Condition. Discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate the 180-day interval is impracticable. If the operator believes that 180 days are impracticable to make a determination about a condition found during an assessment, the pipeline operator must notify PHMSA in accordance with Subsection M of this Section and provide an expected date when adequate information will become available. [49 CFR 195.452(h)(2)]

3. Schedule for Evaluation and Remediation. An operator must complete remediation of a condition according

to a schedule prioritizing the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety or environmental protection. [49 CFR 195.452(h)(3)]

4. Special Requirements for Scheduling Remediation [49 CFR 195.452(h)(4)]

a. Immediate Repair Conditions. An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formulas referenced in Clause H.4.a.ii of this Section. If no suitable remaining strength calculation method can be identified, an operator must implement a minimum 20 percent or greater operating pressure reduction, based on actual operating pressure for two months prior to the date of inspection, until the anomaly is repaired. An operator must treat the following conditions as immediate repair conditions: [49 CFR 195.452(h)(4)(i)]

i. metal loss greater than 80 percent of nominal wall regardless of dimensions; [49 CFR 195.452(h)(4)(i)(A)]

ii. a calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (incorporated by reference, see §30107) and PRCI PR-3-805 (R-STRENG) (incorporated by reference, see §30107). [49 CFR 195.452(h)(4)(i)(B)]

iii. a dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser; [49 CFR 195.452(h)(4)(i)(C)]

iv. a dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6 percent of the nominal pipe diameter; [49 CFR 195.452(h)(4)(i)(D)]

v. an anomaly that in the judgement of the person designated by the operator to evaluate the assessment results requires immediate action. [49 CFR 195.452(h)(4)(i)(E)]

b. 60-Day Conditions. Except for conditions listed in Subparagraph H.4.a of this Section, an operator must schedule evaluation and remediation of the following conditions within 60 days of discovery of condition: [49 CFR 195.452(h)(4)(ii)]

i. a dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3 percent of the pipeline diameter (greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12); [49 CFR 195.452(h)(4)(ii)(A)]

ii. a dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser. [49 CFR 195.452(h)(4)(ii)(B)]

c. 180-Day Conditions. Except for conditions listed in Subsection H.4.(a) or (b) of this Section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition: [49 CFR 195.452(h)(4)(iii)]

i. a dent with a depth greater than 2 percent of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld; [49 CFR 195.452(h)(4)(iii)(A)]

ii. a dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2 percent of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12); [49 CFR 195.452(h)(4)(iii)(B)]

iii. a dent located on the bottom of the pipeline with a depth greater than 6 percent of the pipeline's diameter; [49 CFR 195.452(h)(4)(iii)(C)]

iv. a calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G and PRCI PR-3-805 (R-STRENG).[49 CFR 195.452(h)(4)(iii)(D)]

v. an area of general corrosion with a predicted metal loss greater than 50 percent of nominal wall; [49 CFR 195.452(h)(4)(iii)(E)]

vi. predicted metal loss greater than 50 percent of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld; [49 CFR 195.452(h)(4)(iii)(F)]

vii. a potential crack indication that when excavated is determined to be a crack; [49 CFR 195.452(h)(4)(iii)(G)]

viii. corrosion of or along a longitudinal seam weld; [49 CFR 195.452(h)(4)(iii)(H)]

ix. a gouge or groove greater than 12.5 percent of nominal wall. [49 CFR 195.452(h)(4)(iii)(I)]

d. Other Conditions. In addition to the conditions listed in Subparagraphs H.4.a through c of this Section, an operator must evaluate any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation. §30905, Appendix C of this Subpart contains guidance concerning other conditions that an operator should evaluate. [49 CFR 195.452(h)(4)(iv)]

I. What preventive and mitigative measures must an operator take to protect the high consequence area? [49 CFR 195.452(i)]

1. General Requirements. An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls. [49 CFR 195.452(i)(1)]

2. Risk Analysis Criteria. In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: [49 CFR 195.452(i)(2)]

a. terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area; [49 CFR 195.452(i)(2)(i)]

b. elevation profile; [49 CFR 195.452(i)(2)(ii)]

c. characteristics of the product transported; [49 CFR 195.452(i)(2)(iii)]

d. amount of product that could be released; [49 CFR 195.452 (i)(2)(iv.)]

e. possibility of a spillage in a farm field following the drain tile into a waterway; [49 CFR 195.452(i)(2)(v)]

f. ditches along side a roadway the pipeline crosses; [49 CFR 195.452(i)(2)(vi)]

g. physical support of the pipeline segment such as by a cable suspension bridge; [49 CFR 195.452(i)(2)(vii)]

h. exposure of the pipeline to operating pressure exceeding established maximum operating pressure; [49 CFR 195.452(i)(2)(viii)]

i. seismicity of the area. [49 CFR 195.452(i)(2)(ix)]

3. Leak Detection. An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors―length, and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results. [49 CFR 195.452(i)(3)]

4. Emergency Flow Restricting Devices (EFRD). If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors―the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size. [49 CFR 195.452(i)(4)]

J. What is a continual process of evaluation and assessment to maintain a pipeline's integrity? [49 CFR 195.452(j)]

1. General. After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area. [49 CFR 195.452(j)(1)]

2. Verifying Covered Segments. An operator must verify the risk factors used in identifying pipeline segments that could affect a high consequence area on at least an annual basis not to exceed 15 months (Appendix C of this part provides additional guidance on factors that can influence whether a pipeline segment could affect a high consequence area). If a change in circumstance indicates that the prior consideration of a risk factor is no longer valid or that an operator should consider new risk factors, an operator must perform a new integrity analysis and evaluation to establish the endpoints of any previously identified covered segments. The integrity analysis and evaluation must include consideration of the results of any baseline and periodic integrity assessments (see Subsections B, C, D, and E of this Section), information analyses (see Subsection G of this Section), and decisions about remediation and preventive and mitigative actions (see Subsection H and I of this Section). An operator must complete the first annual verification under this Subsection no later than July 1, 2021. [49 CFR 195.452(j)(2)]

3. Assessment Intervals. An operator must establish five-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in Subsection E of this Section, the analysis of the results from the last integrity assessment, and the information analysis required by Subsection G of this Section. [49 CFR 195.452(j)(3)]

4. Variance from the Five-Year Intervals in Limited Situations [49 CFR 195.452(j)(4)]

a. Engineering Basis. An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in Paragraph J.5 of this Section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval, and propose an alternative interval. An operator must send the notice to the addresses specified in Subsection M of this Section. [49 CFR 195.452(j)(4)(i)]

b. Unavailable Technology. An operator may require a longer assessment period for a segment of line pipe (for example, because sophisticated internal inspection technology is not available). An operator must justify the reasons why it cannot comply with the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must notify OPS 180 days before the end of the five-year (or less) interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed. An operator must send a notice to the addresses specified in Subsection M of this Section. [49 CFR 195.452(j)(4)(ii)]

5. Assessment Methods. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies: [49 CFR 195.452(j)(5)]

a. In-Line Inspection tool or tools capable of detecting corrosion and deformation anomalies, including dents, gouges, and grooves. For pipeline segments that are susceptible to cracks (pipe body and weld seams), an operator must use an in-line inspection tool or tools capable of detecting crack anomalies. When performing an assessment using an in-line inspection tool, an operator must comply with § 30591; [49 CFR 195.452(j)(5)(i)]

b. pressure test conducted in accordance with Chapter 303 of this Subpart [49 CFR 195.452(j)(5)(ii)];

c. external corrosion direct assessment in accordance with §30588; or [49 CFR 195.452(j)(5)(iii)]

d. other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conducting the assessment, by sending a notice to the addresses or facsimile numbers specified in Subsection M of this Section [49 CFR 195.452(j)(5)(iv)].

K. What methods to measure program effectiveness must be used? An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See §30905, Appendix C, of this Subpart for guidance on methods that can be used to evaluate a program's effectiveness. [49 CFR 195.452(k)]

L. What records must an operator keep to demonstrate compliance? [49 CFR 195.452(l)]

1. An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At a minimum, an operator must maintain the following records for review during an inspection: [49 CFR 195.452(l)(1)]

a. a written integrity management program in accordance with Subsection B of this Section; [49 CFR 195.452(l)(1)(i)]

b. documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in Subsection F of this Section. [49 CFR 195.452(l)(1)(ii)]

2. See §30905, Appendix C, of this Subpart for examples of records an operator would be required to keep. [49 CFR 195.452(l)(2)]

M. How does an operator notify PHMSA? An operator must provide any notification required by this section by: [49 CFR 195.452(m)]

1. sending the notification by electronic mail to InformationResourcesManager@dot.gov and Pipeline.inspectors@la.gov ; or [49 CFR 195.452 (m)(1)]

2. sending the notification to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue, SE., Washington, DC 20590, and to the Commissioner of Conservation, Pipeline Safety Section, P.O. Box 94275, Baton Rouge, LA 70804-9275. [195.452(m)(2)]

N. Accommodation of Instrumented Internal Inspection Devices [49 CFR 195.452(n)]

1. Scope. This Subsection does not apply to any pipeline facilities listed in §30177.B. [49 CFR 195.452 (n)(1)]

2. General. An operator must ensure that each pipeline is modified to accommodate the passage of an instrumented internal inspection device by July 2, 2040. [49 CFR 195.452 (n)(2)]

3. Newly Identified Areas. If a pipeline could affect a newly identified high consequence area (see Paragraph D.2 of this Section) after July 2, 2035, an operator must modify the pipeline to accommodate the passage of an instrumented internal inspection device within five years of the date of identification or before performing the baseline assessment, whichever is sooner. [49 CFR 195.452 (n)(3)]

4. Lack of Accommodation. An operator may file a petition under §190.9 of 49 CFR and Chapter 313 of this Subpart for a finding that the basic construction (i.e., length,

diameter, operating pressure, or location) of a pipeline cannot be modified to accommodate the passage of an instrumented internal inspection device or that the operator determines it would abandon or shut-down a pipeline as a result of the cost to comply with the requirement of this section. [49 CFR 195.452 (n)(4)]

5. Emergencies. An operator may file a petition under §190.9 of 49 CFR and Chapter 313 of this Subpart for a finding that a pipeline cannot be modified to accommodate the passage of an instrumented internal inspection device as a result of an emergency. An operator must file such a petition within 30 days after discovering the emergency. If the petition is denied, the operator must modify the pipeline to allow the passage of an instrumented internal inspection device within 1 year after the date of the notice of the denial. [49 CFR 195.452 (n)(5)]

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HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2830 (December 2003), amended LR 30:1216 (June 2004), LR 33:471 (March 2007), LR 35:2797 (December 2009), LR 38:108 (January 2012), LR 44:1029 (June 2018), LR 46:1608 (November 2020).

§30454. Integrity Assessments for Certain Underwater Hazardous Liquid Pipeline Facilities Located in High Consequence Areas [49 CFR 195.454]

A. Notwithstanding any pipeline integrity management program or integrity assessment schedule otherwise required under § 30452, each operator of any underwater hazardous liquid pipeline facility located in a high consequence area that is not an offshore pipeline facility and any portion of which is located at depths greater than 150 feet under the surface of the water must ensure that: [49 CFR 195.454]

1. Pipeline integrity assessments using internal inspection technology appropriate for the integrity threats to the pipeline are completed not less often than once every 12 months, and; [49 CFR 195.454(a)]

2. Pipeline integrity assessments using pipeline route surveys, depth of cover surveys, pressure tests, external corrosion direct assessment, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, are completed on a schedule based on the risk that the pipeline facility poses to the high consequence area in which the pipeline facility is located. [49 CFR 195.454 (b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 46:1610 (November 2020).

Chapter 305. Transportation of Hazardous Liquids by Pipeline—Qualification of Pipeline Personnel [49 CFR Part 195 Subpart G] and Corrosion Control [49 CFR Part 195 Subpart H]

Subchapter A. Qualification of Pipeline Personnel [49 CFR Part 195 Subpart G]

§30501. Scope [49 CFR 195.501]

A. This Subchapter prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility. [49 CFR 195.501(a)]

B. For the purpose of this Subchapter, a covered task is an activity, identified by the operator, that: [49 CFR 195.501(b)]

1. is performed on a pipeline facility; [49 CFR 195.501(b)(1)]

2. is an operations or maintenance task; [49 CFR 195.501(b)(2)]

3. is performed as a requirement of this Subpart; and [49 CFR 195.501(b)(3)]

4. affect the operation or integrity of the pipeline. [49 CFR 195.501(b)(4)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2835 (December 2003).

§30503. Definitions [49 CFR 195.503]

Abnormal Operating Condition—a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

1. indicate a condition exceeding design limits; or

2. result in a hazard(s) to persons, property, or the environment.

Evaluation—a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

1. written examination;

2. oral examination;

3. work performance history review;

4. observation during:

   a. performance on the job;

   b. on the job training; or

c. simulations;

5. other forms of assessment.

Qualified—an individual has been evaluated and can:

1. perform assigned covered tasks; and

2. recognize and react to abnormal operating conditions.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2835 (December 2003).

§30505. Qualification Program [49 CFR 195.505]

A. Each operator shall have and follow a written qualification program. The program shall include provisions to:

1. identify covered tasks; [49 CFR 195.505(a)]

2. ensure through evaluation that individuals performing covered tasks are qualified; [49 CFR 195.505(b)]

3. allow individuals that are not qualified pursuant to this Subchapter to perform a covered task if directed and observed by an individual that is qualified; [49 CFR 195.505(c)]

4. evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an accident as defined in this Subpart; [49 CFR 195.505(d)]

5. evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task; [49 CFR 195.505(e)]

6. communicate changes that affect covered tasks to individuals performing those covered tasks; [49 CFR 195.505(f)]

7. identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed; [49 CFR 195.505(g)]

8. after December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and [49 CFR 195.505(h)]

9. after December 16, 2004, notify the administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the administrator or state agency has verified that it complies with this Section. Notifications to PHMSA may be submitted by electronic mail to InformationResources Manager@dot.gov and to Louisiana Office of Conservation at Pipeline.inspectors@la.gov, or mail to ATTN: Information Resources Manager DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, New Jersey Avenue, S.E. Washington, DC 20590, and to the Commissioner of Conservation, Pipeline Safety Section, P.O. Box 94275, Baton Rouge, LA 70804-9275. [49 CFR 195.505(i)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2835 (December 2003), amended LR 33:471 (March 2007), LR 35:2798 (December 2009), LR 44:1029 (June 2018).

§30507. Record Keeping [49 CFR 195.507]

A. Each operator shall maintain records that demonstrate compliance with this Subchapter.

1. Qualification records shall include: [49 CFR 195.507(a)]

a. identification of qualified individuals(s); [49 CFR 195.507(a)(1)]

b. identification of the covered tasks the individual is qualified to perform; [49 CFR 195.507(a)(2)]

c. date(s) of current qualification; and [49 CFR 195.507(a)(3)]

d. qualification method(s) [49 CFR 195.507(a)(4)]

2. Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years. [49 CFR 195.507(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2836 (December 2003).

§30509. General [49 CFR 195.509]

A. Operators must have a written qualification program by April 27, 2001. The program must be available for review by the administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency [49 CFR 195.509(a)].

B. Operators must complete the qualification of individuals performing covered tasks by October 28, 2002. [49 CFR 195.509(b)]

C. Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999. [49 CFR 195.509(c)]

D. After October 28, 2002, work performance history may not be used as a sole evaluation method. [49 CFR 195.509(d)]

E. After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation [49 CFR 195.509(e)].

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2836 (December 2003), amended LR 33:471 (March 2007).

Subchapter B. Corrosion Control [49 CFR Part 195 Subpart H]

§30551. What do the regulations in this Subchapter cover? [49 CFR 195.551]

A. This Subchapter prescribes minimum requirements for protecting steel pipelines against corrosion.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2836 (December 2003).

§30553. What special definitions apply to this Subchapter? [49 CFR 195.553]

A. As used in this Subchapter:

Active Corrosion—continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety or the environment.

Buried—covered or in contact with soil.

Direct Assessment—an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

Electrical Survey—a series of closely spaced pipe-to-soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

External Corrosion Direct Assessment (ECDA)—a four-step process that combines pre-assessment, indirect inspection, direct examination, and post-assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

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

You—operator.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2836 (December 2003), amended LR 33:471 (March 2007).

§30555. What are the qualifications for supervisors? [49 CFR 195.555]

A. You must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under §30402.C.3 for which they are responsible for insuring compliance.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2836 (December 2003).

§30557. Which pipelines must have coating for external corrosion control? [49 CFR 195.557]

A. Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is:

1. constructed, relocated, replaced, or otherwise changed after the applicable date in §30401.C, not including the movement of pipe covered by §30424; or [49 CFR 195.557(a)]

2. converted under §30111 and: [49 CFR 195.557(b)]

   a. has an external coating that substantially meets §30559 before the pipeline is placed in service; or [49 CFR 195.557(b)(1)]

   b. is a segment that is relocated, replaced, or substantially altered. [49 CFR 195.557(b)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2836 (December 2003).

§30559. What coating material may I use for external corrosion control? [49 CFR 195.559]

A. Coating material for external corrosion control under §30557 must:

1. be designed to mitigate corrosion of the buried or submerged pipeline; [49 CFR 195.559(a)]

2. have sufficient adhesion to the metal surface to prevent under film migration of moisture; [49 CFR 195.559(b)]

3. be sufficiently ductile to resist cracking; [49 CFR 195.559(c)]

4. have enough strength to resist damage due to handling and soil stress; [49 CFR 195.559(d)]

5. support any supplemental cathodic protection; and [49 CFR 195.559(e)]

6. if the coating is an insulating type, have low moisture absorption and provide high electrical resistance. [49 CFR 195.559(f)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2836 (December 2003).

§30561. When must I inspect pipe coating used for external corrosion control? [49 CFR 195.561]

A. You must inspect all external pipe coating required by §30557 just prior to lowering the pipe into the ditch or submerging the pipe. [49 CFR 195.561(a)]

B. You must repair any coating damage discovered. [49 CFR 195.561(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2837 (December 2003).

§30563. Which pipelines must have cathodic protection? [49 CFR 195.563]

A. Each buried or submerged pipeline that is constructed, relocated, replaced, or otherwise changed after the applicable date in §30401.C must have cathodic protection. The cathodic protection must be in operation not later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable. [49 CFR 195.563(a)]

B. Each buried or submerged pipeline converted under §30111 must have cathodic protection if the pipeline: [49 CFR 195.563(b)]

1. has cathodic protection that substantially meets §30571 before the pipeline is placed in service; or [49 CFR 195.563(b)(1)]

2. is a segment that is relocated, replaced, or substantially altered. [49 CFR 195.563(b)(2)]

C. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.[1] Except as provided by Subsection D of this section, this requirement does not apply to breakout tanks and does not apply to buried piping in breakout tank areas and pumping stations until December 29, 2003. [49 CFR 195.563(c)]

D. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where regulations in effect before January 28, 2002 required cathodic protection as a result of electrical inspections. See previous editions of this part in 49 CFR, parts 186 to 199. [49 CFR 195.563(d)]

E. Unprotected pipe must have cathodic protection if required by §30573.B. [49 CFR 195.563(e)]

[1]A pipeline does not have an effective external coating material if the current required to cathodically protect the pipeline is substantially the same as if the pipeline were bare.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2837 (December 2003).

§30565. How do I install cathodic protection on breakout tanks? [49 CFR 195.565]

A. After October 2, 2000, when you install cathodic protection under §30563.A to protect the bottom of an aboveground breakout tank of more than 500 barrels (79.5 m^3) capacity built to API Spec 12F (incorporated by reference, see §30107), API Std 620 (incorporated by reference, see §30107), or API Std 650 (incorporated by reference, see §30107) or API Std 650's predecessor, Standard 12C, you must install the system in accordance with ANSI/API RP 651 (incorporated by reference, see §30107). However, you don't need to comply with ANSI/API RP 651 when installing any tank for which you note in the corrosion control procedures established under §30402.C.3 why compliance with all or certain provisions of API RP 651 is not necessary for the safety of the tank. [49 CFR 195.565]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2837 (December 2003), amended LR 44:1030 (June 2018).

§30567. Which pipelines must have test leads and what must I do to install and maintain the leads? [49 CFR 195.567]

A. General. Except for offshore pipelines, each buried or submerged pipeline or segment of pipeline under cathodic protection required by this Subchapter must have electrical test leads for external corrosion control. However, this requirement does not apply until December 27, 2004 to pipelines or pipeline segments on which test leads were not required by regulations in effect before January 28, 2002. [49 CFR 195.567(a)]

B. Installation. You must install test leads as follows. [49 CFR 195.567(b)]

1. Locate the leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection. [49 CFR 195.567(b)(1)]

2. Provide enough looping or slack so backfilling will not unduly stress or break the lead and the lead will otherwise remain mechanically secure and electrically conductive. [49 CFR 195.567(b)(2)]

3. Prevent lead attachments from causing stress concentrations on pipe. [49 CFR 195.567(b)(3)]

4. For leads installed in conduits, suitably insulate the lead from the conduit. [49 CFR 195.567(b)(4)]

5. At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire. [49 CFR 195.567(b)(5)]

C. Maintenance. You must maintain the test lead wires in a condition that enables you to obtain electrical measurements to determine whether cathodic protection complies with §30571. [49 CFR 195.567(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2837 (December 2003).

§30569. Do I have to examine exposed portions of buried pipelines? [49 CFR 195.569]

A. Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under §30585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion. [49 CFR 195.569]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2837 (December 2003).

§30571. What criteria must I use to determine the adequacy of cathodic protection? [49 CFR 195.571]

A. Cathodic protection required by this Subchapter must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2.2, 6.2.3, 6.2.4, 6.2.5 and 6.3 in NACE SP 0169 (incorporated by reference, see §30107). [49 CFR 195.571]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2838 (December 2003), amended LR 33:472 (March 2007), LR 38:108 (January 2012), LR 44:1030 (June 2018).

§30573. What must I do to monitor external corrosion control? [49 CFR 195.573]

A. Protected Pipelines. You must do the following to determine whether cathodic protection required by this Subchapter complies with §30571. [49 CFR 195.573(a)]

1. Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every three calendar years, but with intervals not exceeding 39 months. [49 CFR 195.573(a)(1)]

2. Identify not more than two years after cathodic protection is installed, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of Paragraph 10.1.1.3 of NACE SP 0169 (incorporated by reference, see §30107). [49 CFR 195.573(a)(2)]

B. Unprotected Pipe. You must reevaluate your unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found, as follows. [49 CFR 195.573(b)]

1. Determine the areas of active corrosion by electrical survey, or where an electrical survey is impractical, by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. [49 CFR 195.573(b)(1)]

2. For the period in the first column, the second column prescribes the frequency of evaluation. [49 CFR 195.573(b)(2)]

Period	Evaluation Frequency
Before December 29, 2003	At least once every 5 calendar years, but with intervals not exceeding 63 months.
Beginning December 29, 2003	At least once every 3 calendar years, but with intervals not exceeding 39 months.

C. Rectifiers and Other Devices. You must electrically check for proper performance each device in the first column at the frequency stated in the second column. [49 CFR 195.573(c)]

Device	Check Frequency
Rectifier Reverse current switch Diode Interference bond whose failure would jeopardize structural protection.	At least six times each calendar year, but with intervals not exceeding 2 1/2 months.
Other interference bond	At least once each calendar year, but with intervals not exceeding 15 months.

D. Breakout Tanks. You must inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API RP 651 (incorporated by reference, see §30107). However, this inspection is not required if you note in the corrosion control procedures established under §30402.C.3 why compliance with all or certain operation and maintenance provisions of API RP 651 is not necessary for the safety of the tank. [49 CFR 195.573(d)]

E. Corrective Action. You must correct any identified deficiency in corrosion control as required by §30401.B. However, if the deficiency involves a pipeline in an integrity management program under §30452, you must correct the deficiency as required by §30452.H. [49 CFR 195.573(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2838 (December 2003), amended LR 33:472 (March 2007), LR 35:2798 (December 2009), LR 38:108 (January 2012), LR 44:1030 (June 2018).

§30575. Which facilities must I electrically isolate and what inspections, tests, and safeguards are required? [49 CFR 195.575]

A. You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit. [49 CFR 195.575(a)]

B. You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. [49 CFR 195.575(b)]

C. You must inspect and electrically test each electrical isolation to assure the isolation is adequate. [49 CFR 195.575(c)]

D. If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing. [49 CFR 195.575(d)]

E. If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices. [49 CFR 195.575(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2838 (December 2003).

§30577. What must I do to alleviate interference currents? [49 CFR 195.577]

A. For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents. [49 CFR 195.577(a)]

B. You must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures. [49 CFR 195.577(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2839 (December 2003).

§30579. What must I do to mitigate internal corrosion? [49 CFR 195.579]

A. General. If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion. [49 CFR 195.579(a)]

B. Inhibitors. If you use corrosion inhibitors to mitigate internal corrosion, you must: [49 CFR 195.579(b)]

1. use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect; [49 CFR 195.579(b)(1)]

2. use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion; and [49 CFR 195.579(b)(2)]

3. examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding 7 1/2 months. [49 CFR 195.579(b)(3)]

C. Removing Pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under §30585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe. [49 CFR 195.579(c)]

D. Breakout Tanks. After October 2, 2000, when you install a tank bottom lining in an aboveground breakout tank built to API Spec 12F (incorporated by reference, see §30107), API Std 620(incorporated by reference, see §30107), API Std 650 (incorporated by reference, see §30107), or API Std 650's predecessor, Standard 12C, you must install the lining in accordance with API RP 652 (incorporated by reference, see §30107). However, you don't need to comply with API RP 652 when installing any tank for which you note in the corrosion control procedures established under §30402.C.3 why compliance with all or certain provisions of API RP 652 is not necessary for the safety of the tank. [49 CFR 195.579(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2839 (December 2003), amended LR 44:1030 (June 2018).

§30581. Which pipelines must I protect against atmospheric corrosion and what coating material may I use? [49 CFR 195.581]

A. You must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under Subsection C of this Section. [49 CFR 195.581(a)]

B. Coating material must be suitable for the prevention of atmospheric corrosion. [49 CFR 195.581(b)]

C. Except portions of pipelines in offshore splash zones or soil-to-air interfaces, you need not protect against atmospheric corrosion any pipeline for which you demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will: [49 CFR 195.581(c)]

1. only be a light surface oxide; or [49 CFR 195.581(c)(1)]

2. not affect the safe operation of the pipeline before the next scheduled inspection. [49 CFR 195.581(c)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2839 (December 2003).

§30583. What must I do to monitor atmospheric corrosion control? [49 CFR 195.583]

A. You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows. [49 CFR 195.583(a)]

If the pipeline is located:	Then the frequency of inspection is:
Onshore	At least once every 3 calendar years, but with intervals not exceeding 39 months.
Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

B. During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water. [49 CFR 195.583(b)]

C. If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by §30581. [49 CFR 195.583(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2839 (December 2003).

§30585. What must I do to correct corroded pipe? [49 CFR 195.585]

A. General Corrosion. If you find pipe so generally corroded that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline, you must replace the pipe. However, you need not replace the pipe if you: [49 CFR 195.585(a)]

1. reduce the maximum operating pressure commensurate with the strength of the pipe needed for serviceability based on actual remaining wall thickness; or [49 CFR 195.585(a)(1)]

2. repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. [49 CFR 195.585(a)(2)]

B. Localized Corrosion Pitting. If you find pipe that has localized corrosion pitting to a degree that leakage might result, you must replace or repair the pipe, unless you reduce the maximum operating pressure commensurate with the strength of the pipe based on actual remaining wall thickness in the pits. [49 CFR 195.585(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2839 (December 2003).

§30587. What methods are available to determine the strength of corroded pipe? [49 CFR 195.587]

A. Under §30585, you may use the procedure in ASME/ANSI B31G, (incorporated by reference, see §30107) or in PRCI PR-3-805 (R-STRENG) (incorporated by reference, see §30107) to determine the strength of corroded pipe based on actual remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures. [49 CFR 195.587]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2840 (December 2003), amended LR 44:1030 (June 2018).

§30588. What standards apply to direct assessment? [49 CFR 195.588]

A. If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion, you must follow the requirements of this Section for performing external corrosion direct assessment. This Section does not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process. [49 CFR 195.588(a)]

B. The requirements for performing external corrosion direct assessment are as follows. [49 CFR 195.588(b)]

1. General. You must follow the requirements of NACE SP0502 (incorporated by reference, see §30107). Also, you must develop and implement an external corrosion direct assessment (ECDA) plan that includes procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment. [49 CFR 195.588(b)(1)]

2. Pre-Assessment. In addition to the requirements in section 3 of NACE SP0502 (incorporated by reference, see §30107), the ECDA plan procedures for pre-assessment must include: [49 CFR 195.588(b)(2)]

a. provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment; [49 CFR 195.588(b)(2)(i)]

b. the basis on which you select at least two different, but complementary, indirect assessment tools to assess each ECDA region; and [49 CFR 195.588(b)(2)(ii)]

c. if you utilize an indirect inspection method not described in appendix A of NACE Standard SP0502 (incorporated by reference, see §30107), you must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method. [49 CFR 195.588(b)(2)(iii)]

3. Indirect examination. In addition to the requirements in Section 4 of NACE SP0502 (incorporated by reference, see §30107), the procedures for indirect examination of the ECDA regions must include: [49 CFR 195.588(b)(3)]

a. provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment; [49 CFR 195.588(b)(3)(i)]

b. criteria for identifying and documenting those indications that must be considered for excavation and direct examination, including at least the following: [49 CFR 195.588(b)(3)(ii)]

i. the known sensitivities of assessment tools; [49 CFR 195.588(b)(3)(ii)(A)]

ii. the procedures for using each tool; and [49 CFR 195.588(b)(3)(ii)(B)]

iii. the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected; [49 CFR 195.588(b)(3)(ii)(C)]

c. for each indication identified during the indirect examination, criteria for: [49 CFR 195.588(b)(3)(iii)]:

i. defining the urgency of excavation and direct examination of the indication; and [49 CFR 195.588(b)(3)(iii)(A)]

ii. defining the excavation urgency as immediate, scheduled, or monitored; and [49 CFR 195.588(b)(3)(iii)(B)]

d. criteria for scheduling excavations of indications in each urgency level. [49 CFR 195.588(b)(3)(iv)]

4. Direct Examination. In addition to the requirements in section 5 of NACE SP0502 (incorporated by reference, see §30107), the procedures for direct examination of indications from the indirect examination must include: [49 CFR 195.588(b)(4)]

a. provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment; [49 CFR 195.588(b)(4)(i)]

b. criteria for deciding what action should be taken if either: [49 CFR 195.588(b)(4)(ii)]

i. corrosion defects are discovered that exceed allowable limits (section 5.5.2.2 of NACE SP0502 (incorporated by reference, see §30107), provides guidance for criteria); or [49 CFR 195.588(b)(4)(ii)(A)]

ii. root cause analysis reveals conditions for which ECDA is not suitable (section 5.6.2 of NACE SP0502 (incorporated by reference, see §30107), provides guidance for criteria); [49 CFR 195.588(b)(4)(ii)(B)]

c. criteria and notification procedures for any changes in the ECDA plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and [49 CFR 195.588(b)(4)(iii)]

d. criteria that describe how and on what basis you will reclassify and re-prioritize any of the provisions specified in section 5.9 of NACE SP0502 (incorporated by reference, see §30107). [49 CFR 195.588(b)(4)(iv)]

5. Post Assessment and Continuing Evaluation. In addition to the requirements in section 6 of NACE SP0502 (incorporated by reference, see §30107), the procedures for post assessment of the effectiveness of the ECDA process must include: [49 CFR 195.588(b)(5)]

a. measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in pipeline segments; and [49 CFR 195.588(b)(5)(i)]

b. criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the pipeline segment at an interval less than that specified in sections 6.2 and 6.3 of NACE SP0502 (see appendix D of NACE SP0502) (incorporated by reference, see §30107). [49 CFR 195.588(b)(5)(ii)]

C. If you use direct assessment on an onshore pipeline to evaluate the effects of stress corrosion cracking, you must develop and follow a Stress Corrosion Cracking Direct Assessment plan that meets all requirements and recommendations of NACE SP0204-2008 (incorporated by reference, see § 30107) and that implements all four steps of the Stress Corrosion Cracking Direct Assessment process including pre- assessment, indirect inspection, detailed examination and post- assessment. As specified in NACE SP0204-2008, Section 1.1.7, Stress Corrosion Cracking Direct Assessment is complementary with other inspection methods such as in-line inspection or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for: [49 CFR 195.588(c)]

1. data gathering and integration. An operator's plan must provide for a systematic process to collect and evaluate data to identify whether the conditions for stress corrosion cracking are present and to prioritize the segments for assessment in accordance with NACE SP0204- 2008, Sections 3 and 4, and Table 1. This process must also include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204-2008 indicate the potential for Stress Corrosion Cracking Direct Assessment. This data gathering process must be conducted in accordance with NACE SP0204-2008, Section 5.3, and must include, at a minimum, all data listed in NACE SP0204-2008, Table 2. Further, an operator must analyze the following factors as part of this evaluation: [49 CFR 195.588(c)(1)]

a. the effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment such as soil temperature, moisture, factors that affect the rate of carbon dioxide generation, and/or cathodic protection; [49 CFR 195.588(c)(1)(i)]

b. the effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments; [49 CFR 195.588(c)(1)(ii)]

c. the effects of variations in applied cathodic protection such as overprotection, cathodic protection loss for extended periods, and high negative potentials; [49 CFR 195.588(c)(1)(iii)]

d. the effects of coatings that shield cathodic protection when disbonded from the pipe; [49 CFR 195.588(c)(1)(iv)]

e. other factors that affect the mechanistic properties associated with SCC including but not limited to operating pressures, high tensile residual stresses, and the presence of sulfides; [49 CFR 195.588(c)(1)(v)]

2. indirect inspection. In addition to the requirements and recommendations of NACE SP0204-2008, Section 4, the plan's procedures for indirect inspection must include provisions for conducting at least two different, but complementary, indirect assessment electrical surveys, and the basis on the selections as the most appropriate for the pipeline segment based on the data gathering and integration step; [49 CFR 195.588(c)(2)]

3. direct examination. In addition to the requirements and recommendations of NACE SP0204-2008, section 5, the plan's procedures for direct examination must provide for conducting a minimum of four direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur; [49 CFR 195.588(c)(3)]

4. remediation and mitigation. If any indication of SCC is discovered in a segment, an operator must mitigate the threat in accordance with one of the following applicable methods: [49 CFR 195.588(c)(4)]

a. non-significant SCC, as defined by NACE SP0204-2008, may be mitigated by either hydrostatic testing in accordance with Subparagraph B.4.ii of this Section, or by grinding out with verification by Non-Destructive Examination (NDE) methods that the SCC defect is removed and repairing the pipe. If grinding is used for repair, the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG (incorporated by reference, see §30107) and must be sufficient to meet the design requirements of Subpart C of this Part; [49 CFR 195.588(c)(4)(i)]

b. significant SCC must be mitigated using a hydrostatic testing program with a minimum test pressure between 100 percent up to 110 percent of the specified minimum yield strength for a 30-minute spike test immediately followed by a pressure test in accordance with Subpart E of this Part. The test pressure for the entire sequence must be continuously maintained for at least 8 hours, in accordance with subpart E of this part. Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment retested until the pipe passes the complete test without leakage. Pipe segments that have SCC present, but that pass the pressure test, may be repaired by grinding in accordance with Subparagraph C.4.i of this Section; [49 CFR 195.588(c)(4)(ii)]

5. Post Assessment. In addition to the requirements and recommendations of NACE SP0204-2008, sections 6.3, periodic reassessment, and 6.4, effectiveness of Stress Corrosion Cracking Direct Assessment, the plan's procedures for post assessment must include development of a reassessment plan based on the susceptibility of the operator's pipe to Stress Corrosion Cracking as well as on the behavior mechanism of identified cracking. Factors to be considered include, but are not limited to: [49 CFR 195.588(c)(5)]

a. evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204-2008, sections 5.3.5.7, 5.4, and 5.5; [49 CFR 195.588(c)(5)(i)]

b. conditions conducive to creation of the carbonate-bicarbonate environment; [49 CFR 195.588(c)(5)(ii)]

c. conditions in the application (or loss) of cathodic protection that can create or exacerbate SCC; [49 CFR 195.588(c)(5)(iii)]

d. operating temperature and pressure conditions; [49 CFR 195.588(c)(5)(iv)]

e. cyclic loading conditions; [49 CFR 195.588(c)(5)(v)]

f. conditions that influence crack initiation and growth rates; [49 CFR 195.588(c)(51)(vi)]

g. the effects of interacting crack clusters; [49 CFR 195.588(c)(5)(vii)]

h. the presence of sulfides; and [49 CFR 195.588(c)(5)(viii)]

i. conditions conducive to creation of the carbonate-bicarbonate environment. [49 CFR 195.588(c)(5)(ix)]

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§30589. What corrosion control information do I have to maintain? [49 CFR 195.589]

A. You must maintain current records or maps to show the location of: [49 CFR 195.589(a)]

1. cathodically protected pipelines; [49 CFR 195.589(a)(1)]

2. cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and [49 CFR 195.589(a)(2)]

3. neighboring structures bonded to cathodic protection systems. [49 CFR 195.589(a)(3)]

B. Records or maps showing a stated number of anodes, installed a stated manner or spacing, need not show specific distances to each buried anode. [49 CFR 195.589(b)]

C. You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this Subchapter in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least five years, except that records related to §§30569, 30573.A and B, and 30579.B.3 and C must be retained for as long as the pipeline remains in service. [49 CFR 195.589(c)]

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§30591. In-Line Inspection of Pipelines [49 CFR 195.591]

A. When conducting in-line inspection of pipelines required by this part, each operator must comply with the requirements and recommendations of API Std 1163, Inline Inspection Systems Qualification Standard; ANSI/ASNT ILI-PQ, Inline Inspection Personnel Qualification and Certification; and NACE SP0102-2010, Inline Inspection of Pipelines (incorporated by reference, see §30107). An in-line inspection may also be conducted using tethered or remote control tools provided they generally comply with those sections of NACE SP0102-2010 that are applicable. [49 CFR 195.591(a)]

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Chapter 309. Transportation of Hazardous Liquids by Pipeline—Appendices [49 CFR Part 195]

§30901. Reserved.

§30903. Reserved.

§30905. Appendix C to Subpart 3—Guidance for Implementation of Integrity Management Program [49 CFR Part 195 Appendix C]

A. This appendix gives guidance to help an operator implement the requirements of the integrity management program rule in §30450 and §30452. Guidance is provided on:

1. information an operator may use to identify a high consequence area and factors an operator can use to consider the potential impacts of a release on an area;

2. risk factors an operator can use to determine an integrity assessment schedule;

3. safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported, an operator may use to determine if a pipeline segment falls into a high, medium or low risk category;

4. types of internal inspection tools an operator could use to find pipeline anomalies;

5. measures an operator could use to measure an integrity management program's performance;

6. types of records an operator will have to maintain; and

7. types of conditions that an integrity assessment may identify that an operator should include in its required schedule for evaluation and remediation.

I. Identifying a High Consequence Area and Factors for Considering a Pipeline Segment's Potential Impact on a High Consequence Area

A. The rule defines a high consequence area as a high population area, another populated area, an unusually sensitive area, or a commercially navigable waterway. The Office of Pipeline Safety (OPS) will map these areas on the National Pipeline Mapping System (NPMS). An operator, member of the public, or other government agency may view and download the data from the NPMS home page http://www.npms.phmsa.gov/. OPS will maintain the NPMS and update it periodically. However, it is an operator's responsibility to ensure that it has identified all high consequence areas that could be affected by a pipeline segment. An operator is also responsible for periodically evaluating its pipeline segments to look for population or environmental changes that may have occurred around the pipeline and to keep its program current with this information. (Refer to §30452.D.3.) For more information to help in identifying high consequence areas, an operator may refer to:

1. Digital Data on populated areas available on U.S. Census Bureau maps;

2. Geographic Database on the commercial navigable waterways available on http://www.bts.gov/gis/ntatlas/networks.html;

3. the Bureau of Transportation Statistics database that includes commercially navigable waterways and non-commercially navigable waterways. The database can be downloaded from the BTS website at http://www.bts.gov/gis/ntatlas/networks.html.

B. The rule requires an operator to include a process in its program for identifying which pipeline segments could affect a high consequence area and to take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. (See §30452.F and I.) Thus, an operator will need to consider how each pipeline segment could affect a high consequence area. The primary source for the listed risk factors is a US DOT study on instrumented Internal Inspection devices (November 1992). Other sources include the National Transportation Safety Board, the Environmental Protection Agency and the Technical Hazardous Liquid Pipeline Safety Standards Committee. The following list provides guidance to an operator on both the mandatory and additional factors:

1. terrain surrounding the pipeline. An operator should consider the contour of the land profile and if it could allow the liquid from a release to enter a high consequence area. An operator can get this information from topographical maps such as U.S. Geological Survey quadrangle maps;

2. drainage systems such as small streams and other smaller waterways that could serve as a conduit to a high consequence area;

3. crossing of farm tile fields. An operator should consider the possibility of a spillage in the field following the drain tile into a waterway;

4. crossing of roadways with ditches along the side. The ditches could carry a spillage to a waterway;

5. the nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly

volatile liquids, etc.) Highly volatile liquids become gaseous when exposed to the atmosphere. A spillage could create a vapor cloud that could settle into the lower elevation of the ground profile;

6. physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance;

7. operating conditions of the pipeline (pressure, flow rate, etc.) Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure;

8. the hydraulic gradient of the pipeline;

9. the diameter of the pipeline, the potential release volume, and the distance between isolation points;

10. potential physical pathways between the pipeline and the high consequence area;

11. response capability (time to respond, nature of response);

12. potential natural forces inherent in the area (flood zones, earthquakes, subsidence areas, etc.).

II. Risk Factors for Establishing Frequency of Assessment

A. By assigning weights or values to the risk factors, and using the risk indicator tables, an operator can determine the priority for assessing pipeline segments, beginning with those segments that are of highest risk, that have not previously been assessed. This list provides some guidance on some of the risk factors to consider (see §30452.E). An operator should also develop factors specific to each pipeline segment it is assessing, including:

1. populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate;

2. results from previous testing/inspection. (See §30452.H.);

3. leak history. (See leak history risk table.);

4. known corrosion or condition of pipeline. (See §30452.G.);

5. cathodic protection history;

6. type and quality of pipe coating (disbonded coating results in corrosion);

7. age of pipe (older pipe shows more corrosion-may be uncoated or have an ineffective coating) and type of pipe seam. (See Age of Pipe risk table.);

8. product transported (highly volatile, highly flammable and toxic liquids present a greater threat for both people and the environment)(see Product transported risk table.);

9. pipe wall thickness (thicker walls give a better safety margin);

10. size of pipe (higher volume release if the pipe ruptures);

11. location related to potential ground movement (e.g., seismic faults, rock quarries, and coal mines); climatic (permafrost causes settlement-Alaska); geologic (landslides or subsidence);

12. security of throughput (effects on customers if there is failure requiring shutdown);

13. time since the last internal inspection/pressure testing;

14. with respect to previously discovered defects/anomalies, the type, growth rate, and size;

15. operating stress levels in the pipeline;

16. location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose);

17. physical support of the segment such as by a cable suspension bridge;

18. non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).

B. Example. This example illustrates a hypothetical model used to establish an integrity assessment schedule for a hypothetical pipeline segment. After we determine the risk factors applicable to the pipeline segment, we then assign values or numbers to each factor, such as, high (5), moderate (3), or low (1). We can determine an overall risk classification (A, B, C) for the segment using the risk tables and a sliding scale (values 5 to 1) for risk factors for which tables are not provided. We would classify a segment as C if it fell above 2/3 of maximum value (highest overall risk value for any one segment when compared with other segments of a pipeline), a segment as B if it fell between 1/3 to 2/3 of maximum value, and the remaining segments as A.

i. For the baseline assessment schedule, we would plan to assess 50 percent of all pipeline segments covered by the rule, beginning with the highest risk segments, within the first 3 1/2 years and the remaining segments within the seven-year period. For the continuing integrity assessments, we would plan to assess the C segments within the first two years of the schedule, the segments classified as moderate risk no later than year three or four and the remaining lowest risk segments no later than year five.

ii. For our hypothetical pipeline segment, we have chosen the following risk factors and obtained risk factor values from the appropriate table. The values assigned to the risk factors are for illustration only.

Age of pipeline:	Assume 30 years old (refer to “Age of Pipeline” risk table)	Risk Value=5
Pressure tested:	Tested once during construction	Risk Value=5
Coated:	(yes/no)—yes	
Coating Condition:	Recent excavation of suspected areas showed holidays in coating (potential corrosion risk)	Risk Value=5
Cathodically Protected:	(yes/no)—yes	Risk Value=1
Date cathodic protection installed:	Five years after pipeline was constructed (Cathodic protection installed within one year of the pipeline’s construction is generally considered low risk.)	Risk Value=3
Close interval survey:	(yes/no)—no	Risk Value=3
Internal Inspection tool used:	(yes/no)—yes	
Date of pig run?	In last five years	Risk Value=1
Anomalies found:	(yes/no)—yes, but do not pose an immediate safety risk or environmental hazard	Risk Value=3
Leak History:	yes, one spill in last 10 years. (refer to “Leak History” risk table)	Risk Value=2
Product transported:	Diesel fuel. Product low risk. (refer to “Product” risk table)	Risk Value=1

iii. Overall risk value for this hypothetical segment of pipe is 34. Assume that we have two other pipeline segments for which we conduct similar risk rankings. The second pipeline segment has an overall risk value of 20, and the third segment, 11. For the baseline assessment we would establish a schedule where we assess the first segment (highest risk segment) within two years, the second segment within five years and the third segment within seven years. Similarly, for the continuing integrity assessment, we could establish an assessment schedule where we assess the highest risk segment no later than the second year, the second segment no later than the third year, and the third segment no later than the fifth year.

III. Safety Risk Indicator Tables for Leak History, Volume or Line Size, Age of Pipeline, and Product Transported

Leak History	
Safety Risk Indicator	**Leak History (Time-dependent defects)[1]**
High	>3 Spills in last 10 years
Low	<3 Spills in last 10 years

[1] Time-dependent defects are those that result in spills due to corrosion, gouges, or problems developed during manufacture, construction or operation, etc.

Line Size or Volume Transported	
Safety Risk Indicator	**Line Size**
High	$\geq$ 18”
Moderate	10”-16” nominal diameters
Low	$\leq$ 8” nominal diameter

Age of Pipeline	
Safety Risk Indicator	**Age Pipeline Condition Dependent[2]**
High	> 25 years
Low	< 25 years

2Depends on pipeline’s coating and corrosion condition, and steel quality, toughness, welding.

Product Transported		
Safety Risk Indicator	**Considerations [3]**	**Product Examples**
High	(Highly volatile and flammable)	(Propane, butane, Natural Gas Liquid (NGL), ammonia).
	Highly toxic	(Benzene, high Hydrogen Sulfide content crude oils).
Medium	Flammable-flashpoint<100F	(Gasoline, JP4, low flashpoint crude oils).
Low	Non-flammable-flashpoint 100+F	(Diesel, fuel oil, kerosene, JP5, most crude oils).

[3] The degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; and volatility, flammability, and water solubility determine the Product Indicator. Comprehensive Environmental Response, Compensation and Liability Act Reportable Quantity values may be used as an indication of chronic toxicity. National Fire Protection Association health factors may be used for rating acute hazards.

IV. Types of Internal Inspection Tools to Use

An operator should consider at least two types of internal inspection tools for the integrity assessment from the following list. The type of tool or tools an operator selects will depend on the results from previous internal inspection runs, information analysis and risk factors specific to the pipeline segment:

1. geometry internal inspection tools for detecting changes to ovality, e.g., bends, dents, buckles or wrinkles, due to construction flaws or soil movement, or other outside force damage;

2. metal loss tools (ultrasonic and magnetic flux leakage) for determining pipe wall anomalies, e.g., wall loss due to corrosion;

3. crack detection tools for detecting cracks and crack-like features, e.g., stress corrosion cracking (SCC), fatigue cracks, narrow axial corrosion, toe cracks, hook cracks, etc.

V. Methods to Measure Performance

A. General

1. This guidance is to help an operator establish measures to evaluate the effectiveness of its integrity management program. The performance measures required will depend on the details of each integrity management program and will be based on an understanding and analysis of the failure mechanisms or threats to integrity of each pipeline segment.

2. An operator should select a set of measurements to judge how well its program is performing. An operator’s objectives for its program are to ensure public safety, prevent or minimize leaks and spills and prevent property and environmental damage. A typical integrity management program will be an ongoing program it may contain many elements. Therefore, several performance measures are likely to be needed to measure the effectiveness of an ongoing program.

B. Performance Measures. These measures show how a program to control risk on pipeline segments that could affect a high consequence area is progressing under the integrity management requirements. Performance measures generally fall into three categories.

1. Selected Activity Measures—Measures that monitor the surveillance and preventive activities the operator has implemented. These measures indicate how well an operator is implementing the various elements of its integrity management program.

2. Deterioration Measures—Operation and maintenance trends that indicate when the integrity of the system is weakening despite preventive measures. This category of performance measure may indicate that the system condition is deteriorating despite well executed preventive activities.

3. Failure Measures—Leak History, incident response, product loss, etc. These measures will indicate progress towards fewer spills and less damage.

C. Internal vs. External Comparisons. These comparisons show how a pipeline segment that could affect a high consequence area is progressing in comparison to the operator’s other pipeline segments that are not covered by the integrity management requirements and how that pipeline segment compares to other operator’s pipeline segments.

1. Internal—Comparing data from the pipeline segment that could affect the high consequence area with data from pipeline segments in other areas of the system may indicate the effects from the attention given to the high consequence area.

2. External—Comparing data external to the pipeline segment (e.g., OPS incident data) may provide measures on the frequency and size of leaks in relation to other companies.

D. Examples. Some examples of performance measures an operator could use include:

1. a performance measurement goal to reduce the total volume from unintended releases by __ percent (percent to be determined by operator) with an ultimate goal of zero;

2. a performance measurement goal to reduce the total number of unintended releases (based on a threshold of 5 gallons) by __ percent (percent to be determined by operator) with an ultimate goal of zero;

3. a performance measurement goal to document the percentage of integrity management activities completed during the calendar year;

4. a performance measurement goal to track and evaluate the effectiveness of the operator’s community outreach activities;

5. a narrative description of pipeline system integrity, including a summary of performance improvements, both qualitative and quantitative, to an operator’s integrity management program prepared periodically;

6. a performance measure based on internal audits of the operator's pipeline system per this Subpart;

7. a performance measure based on external audits of the operator's pipeline system per this Subpart;

8. a performance measure based on operational events (for example: relief occurrences, unplanned valve closure, SCADA outages, etc.) that have the potential to adversely affect pipeline integrity;

9. a performance measure to demonstrate that the operator's integrity management program reduces risk over time with a focus on high risk items;

10. a performance measure to demonstrate that the operator's integrity management program for pipeline stations and terminals reduces risk over time with a focus on high risk items.

VI. Examples of Types of Records an Operator Must Maintain

The Rule requires an operator to maintain certain records. (See §30452.L). This Section provides examples of some records that an operator would have to maintain for inspection to comply with the requirement. This is not an exhaustive list:

1. a process for identifying which pipelines could affect a high consequence area and a document identifying all pipeline segments that could affect a high consequence area;

2. a plan for baseline assessment of the line pipe that includes each required plan element;

3. modification to the baseline plan and reasons for the modification;

4. use of and support for an alternative practice;

5. a framework addressing each required element of the integrity management program, updates and changes to the initial framework and eventual program;

6. a process for identifying a new high consequence area and incorporating it into the baseline plan, particularly, a process for identifying population changes around a pipeline segment;

7. an explanation of methods selected to assess the integrity of line pipe;

8. a process for review of integrity assessment results and data analysis by a person qualified to evaluate the results and data;

9. the process and risk factors for determining the baseline assessment interval;

10. results of the baseline integrity assessment;

11. the process used for continual evaluation, and risk factors used for determining the frequency of evaluation;

12. process for integrating and analyzing information about the integrity of a pipeline, information and data used for the information analysis;

13. results of the information analyses and periodic evaluations;

14. the process and risk factors for establishing continual reassessment intervals;

15. justification to support any variance from the required reassessment intervals;

16. integrity assessment results and anomalies found, process for evaluating and remediating anomalies, criteria for remedial actions and actions taken to evaluate and remediate the anomalies;

17. other remedial actions planned or taken;

18. schedule for evaluation and remediation of anomalies, justification to support deviation from required remediation times;

19. risk analysis used to identify additional preventive or mitigative measures, records of preventive and mitigative actions planned or taken;

20. criteria for determining EFRD installation;

21. criteria for evaluating and modifying leak detection capability;

22. methods used to measure the program's effectiveness.

VII. Conditions That May Impair a Pipeline's Integrity

Section 30452.H requires an operator to evaluate and remediate all pipeline integrity issues raised by the integrity assessment or information analysis. An operator must develop a schedule that prioritizes conditions discovered on the pipeline for evaluation and remediation. The following are some examples of conditions that an operator should schedule for evaluation and remediation:

A. any change since the previous assessment;

B. mechanical damage that is located on the top side of the pipe;

C. an anomaly abrupt in nature;

D. an anomaly longitudinal in orientation;

E. an anomaly over a large area;

F. an anomaly located in or near a casing, a crossing of another pipeline, or an area with suspect cathodic protection.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2840 (December 2003), repromulgated LR 30:260 (February 2004), amended LR 30:1217 (June 2004), LR 38:109 (January 2012).

Chapter 313. Hazardous Liquids Pipeline Enforcement

§31301. Scope

A. This regulation prescribes the authority of the assistant secretary of the Office of Conservation and procedures to be utilized by him in carrying out his duties regarding administration and enforcement of R.S. 30:701 et seq., and the rules and regulations promulgated thereunder.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2844 (December 2003).

§31303. Service

A. Except as herein provided, any order, notice or other documents required to be served under this regulation shall be served personally or by registered or certified mail.

B. Should the assistant secretary elect to make personal service, it may be made by any officer authorized to serve process or any agent or employee of the assistant secretary in the same manner as is provided by law for the service of citation in civil actions in the district courts. Proof of service by an agent or employee shall be by the affidavit of the person making it.

C. Service upon a person's duly authorized representative, officer or agent constitutes service upon that person.

D. Service by registered or certified mail is complete upon mailing. An official U.S. Postal Service receipt from the registered or certified mailing constitutes prima facie evidence of service.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2844 (December 2003).

§31305. Subpoenas

A. The assistant secretary may sign and issue subpoenas either on his own initiative or, upon request and adequate showing by any person participating in any proceeding before the assistant secretary that the information sought is relevant and will materially advance the proceeding.

B. A subpoena may require the attendance of a witness for the purpose of giving testimony, or the production of documents or other tangible evidence in the possession or under the control of the person served, or both.

C. A subpoena may be served by any agent of the Department of Conservation, by the sheriff of the parish where service is to be made or the parish where the action is pending or by any other person authorized by law to serve process in this state.

D. Service of a subpoena upon the person named therein shall be made by delivering a copy of the subpoena to such person. Delivery of a copy of a subpoena may be made by handing them to the person, leaving them at his office with persons in charge thereof, leaving them at his dwelling place or usual place of abode with some person of suitable age and discretion then residing therein, or by any method whereby actual notice is given to him.

E. When the person to be served is not a natural person, delivery of a copy of the subpoena may be affected by handing them to a designated agent or representative for service, or to any officer, director, or agent in charge of any office of the person.

F. The original subpoena bearing a certificate of service shall be filed in the assistant secretary's records for the proceedings in connection with which the subpoena was issued.

G. No person shall be excused from attending and testifying or producing books, papers, or records, or from obeying the subpoena of the assistant secretary, or of a court of record on the grounds that the testimony or evidence required of him may tend to incriminate him or subject him to penalty or forfeiture. Pursuant to R.S. 30:8(4), no natural person shall be subject to criminal prosecution or to any penalty or forfeiture on account of anything concerning which he may be required to testify or produce evidence before the assistant secretary or a court of law; however, no person testifying shall be exempt from prosecution and punishment for perjury.

H. In the case of failure or refusal of a person to comply with a subpoena issued by the assistant secretary, or in the case of a refusal of a witness to testify or answer as to a matter regarding which he may be lawfully interrogated, any district court on the application of the assistant secretary may, in term time or in vacation, issue an attachment for the person to compel him to comply with the subpoena and to attend before the assistant secretary with the desired documents and to give his testimony upon whatever matters are lawfully required. The court may punish for contempt those disobeying its orders as in the case of disobedience of a subpoena issued by the court or refusal to testify therein.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2844 (December 2003).

§31307. Inspection, Field Inspection Reports

A. Officers, employees or agents authorized by the assistant secretary, upon presenting proper credentials, are authorized to enter upon, inspect and examine, at reasonable times and in a reasonable manner, the records and properties of persons to the extent that such records and properties are relevant to determining compliance of such person with R.S. 30:701 et seq. or any rules, regulations or orders issued thereunder.

B. Inspection may be conducted pursuant to a routine schedule, a complaint received from a member of the public, information obtained from a previous inspection, report of accident or incident involving facilities, or whenever deemed appropriate by the assistant secretary.

C. If, after inspection, the assistant secretary believes that further information is needed or required to determine compliance or appropriate action, the assistant secretary may request specific information of the person or operator to be answered within ten days of receipt of said request.

D. The assistant secretary may, to the extent necessary to carry out his responsibilities, require reasonable testing of any portion of a facility in connection with a violation or suspected violation.

E. When information obtained from an inspection indicates that a violation has probably occurred, the inspector shall complete a field inspection report as to the nature of the violation citing the specific provisions which have been violated. Said field inspection report shall be filed with the assistant secretary for review and further action, if appropriate.

F. The assistant secretary or his agent, after review of the field inspection report, and depending upon the severity of the violation and the exigency of the situation, may issue to the operator a letter of non-compliance or initiate one or more enforcement proceedings prescribed by §31311-§31314.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2845 (December 2003).

§31309. Letter of Non-Compliance; Relief Therefrom

A. Upon determination that a probable violation of R.S. 30:701 et seq., or any rule, regulation or order issued thereunder has occurred, the assistant secretary may institute enforcement procedures by serving upon the hazardous liquid pipeline operator a letter of non-compliance notifying said operator of said probable violation and directing said operator to correct said violation within a designated period of time to be determined by the assistant secretary or be subject to enforcement action prescribed by §§31311-31319. A copy of the field inspection report or other evidence of violation shall be attached to the letter of non-compliance.

The letter of non-compliance may inform the operator of the time at which reinspection of the facility will be conducted to confirm compliance and shall inform the operator of the time delays and procedure available to said operator for securing relief from said letter of non-compliance.

B. Except in cases of emergency action instituted pursuant to §31315, within seven days of receipt of a letter of non-compliance, the operator who believes himself to be in compliance with the applicable statute and the rules, regulations or orders issued thereunder or who believes the time limits imposed upon him for compliance to be burdensome, may request a conference before the assistant secretary or his designated agent. The operators request for said conference may be verbal or presented in writing.

C. The conference before the assistant secretary or his agent shall be informal without strict adherence to rules of evidence. The operator may submit any relevant information and materials which shall become part of the record and may examine the assistant secretary's files relative to the probable violation. If circumstances are deemed appropriate by the assistant secretary and upon request of the operator, this conference may be held by telephone conference.

D. Upon conclusion of the conference for relief, the assistant secretary may issue to the operator a modified letter of non-compliance extending the time for compliance or containing such other terms and conditions as may be appropriate considering the nature of the probable violation, the circumstances and exigency of the situation.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2845 (December 2003).

§31311. Reinspection, Show Cause Conference

A. Upon expiration of the delay allowed in the letter of non-compliance or modified letter of non-compliance for correcting said probable violation, the operator's facilities shall be reinspected and if the operator is found to be in compliance, the enforcement file for said violation will be closed.

B. If upon reinspection the operator is found to be in violation of the statute, rule or regulation for which a letter of non-compliance has been issued, the assistant secretary may:

1. re-issue citation to the operator in the form of a letter of non-compliance containing such modifications or extensions of time as the case may warrant;

2. require that the operator attend a show cause conference with the assistant secretary or his agent to review the complaint and the operator's efforts in resolving or correcting the violation and at the conclusion of said conference the assistant secretary may re-issue a modified letter of non-compliance containing such modifications or extensions of time as the case may warrant; or

3. immediately after reinspection or after the show cause conference, initiate one or more enforcement proceedings prescribed by §§31313-31319.

C. The show cause conference shall be conducted informally without strict adherence to the rules of evidence.. The operator may submit any relevant information, call witnesses on his behalf, and examine the evidence and witnesses against him. No detailed record of said conference shall be prepared but said record shall contain the materials in the enforcement case file pertinent to the issues, relevant submissions of the operator and the written recommendations of the assistant secretary or his agent.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2845 (December 2003).

§31313. Show Cause Hearing, Notice, Rules of Procedure, Record, Order of Compliance

A. At any time that the assistant secretary determines that such action is appropriate, he may direct that an operator attend a formal show cause hearing and to show cause at said hearing why he should not be compelled to comply with applicable statutes and the rules and regulations promulgated thereunder.

B. The operator shall be given at least 10 days notice of said show cause hearing in the manner herein provided and shall be required to attend. The assistant secretary may issue such subpoenas as may be necessary for the attendance of witnesses and the production of documents.

C. The show cause hearing shall be conducted in accordance with the procedures for adjudication prescribed by the Administrative Procedure Act (R.S. 49:950 et seq.).

D. The record of the case shall include those items required by R.S. 49:955(E) together with the enforcement file for the violation in question which enforcement file may include inspection reports and other evidence of violation, letters of non-compliance, modified letters of non-compliance, materials submitted by the operator pursuant to §31309 and §31311, all correspondence and orders directed to the operator by the assistant secretary, all correspondence received by the assistant secretary from the operator, and evaluations and recommendations of the assistant secretary or his staff.

E. After conclusion of the show cause hearing the assistant secretary shall issue an order of compliance directed to the operator setting forth findings and determinations on all material issues, including a determination as to whether each alleged violation has been proven, and a statement of the actions required to be taken by the operator and the time by which such actions must be accomplished. The compliance order shall become final as specified by the Administrative Procedure Act.

F. The assistant secretary may tax the operator with all costs of said hearing including but not limited to transcription and service costs and hearing fees in the amount prescribed by R.S. 30:21.

G. The operator and the assistant secretary may consent to waiver of the show cause hearing and enter into a consent order which will become final and non-appealable upon its issuance.

H. If the operator fails to comply with the final order of compliance, the assistant secretary may take whatever civil or criminal action is necessary to enforce said order.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2846 (December 2003).

§31315. Emergency

A. Should the assistant secretary, the director of pipelines or the chief of pipeline safety find an existing emergency due to non-compliance with law or the rules, regulations or orders issued pursuant thereto or due to leakage or other hazard which in his judgment requires the issuance of an emergency order or an order for the immediate termination of the offending service without first complying with the procedures set forth herein and without having a hearing, he may issue the emergency order or terminate said offending service and invoke a show cause hearing pursuant to §31313 requiring the operator to show cause why the circumstances giving rise to the emergency should not be corrected. The emergency order or order for termination of the offending service shall remain in force no longer than 15 days from its effective date. In any event, the emergency order shall expire when the order made after notice and hearing with respect to the same subject matter becomes effective. An emergency is defined as any situation where there is a substantial likelihood that loss of life, personal injury, health or property will result before the procedures under this regulation for notice and hearing can be fully complied with.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2846 (December 2003).

§31317. Hazardous Facility Orders

A. Notwithstanding any self imposed regulatory limitations, if the assistant secretary finds, after reasonable notice and an opportunity to be heard in accordance with §31313, a particular pipeline facility subject to R.S. 30:701 to be hazardous to life or property, he may issue an order requiring the owner or operator of the facility to take corrective action. Corrective action may include suspended or restricted use of the facility, inspection, testing, repair, replacement, or other action as appropriate. The provisions of §31315 shall also be applicable for issuance of hazardous facility orders on an emergency basis.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2846 (December 2003).

§31319. Civil Enforcement, Injunction

A. Whenever it appears to the assistant secretary that any person or operator has engaged, is engaged, or is about to engage in any act or practice constituting a violation of R.S. 30:701 et seq., or any rule, regulation or order issued thereunder, he may bring an action in the court having jurisdiction, to enjoin such acts or practice and to enforce compliance with the applicable statute and the rules, regulations and orders issued pursuant thereto, and upon proper showing a temporary restraining order or a preliminary or permanent injunction shall be granted without bond. The relief sought may include a mandatory injunction commanding any person to comply with the applicable law or any rule, regulation or order issued thereunder, and to make restitution of money received in violation of any such rule, regulation or order.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2846 (December 2003).

§31321. Violation, Penalties

A. After notice and opportunity to be heard, in accordance with §31313, the assistant secretary may, after determining that a person has violated any provision of R.S. 30:701, et seq., or any rule, regulation or order issued pursuant thereto, assess a civil penalty upon or against said person not to exceed the amounts fixed by statute, particularly, but not exclusively, R.S. 30:705. The amount of the penalty shall be assessed by the assistant secretary by written notice. In determining the amount of penalty, the assistant secretary shall consider the nature, circumstances, and gravity of the violation and, with respect to the person found to have committed the violation, the degree of culpability, any history of prior effect on ability to continue to do business, any good faith in attempting to achieve compliance, ability to pay the penalty, and such other matters as justice may require.

B. The assistant secretary may transmit such evidence as may be available concerning acts or practice in violation or R.S. 30:701, et seq. or any rules, regulation or order issued pursuant thereto or any order issued pursuant to this regulation to the district attorney having jurisdiction over same who, in his discretion, may institute necessary proceedings to collect the fines and impose the penalties provided by statute.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2846 (December 2003).

§31323. Waiver of Compliance with Standards

A. Upon application by any person engaged in the transportation of hazardous liquids or the operation of intrastate pipeline facilities, the assistant secretary shall, by order, after notice and opportunity for hearing and under such terms and conditions and to such extent as the assistant secretary may deem reasonable and proper, waive in whole or in part compliance with any standard established under R.S. 30:701 et seq., if he determines that compliance with such standard works a substantial hardship on an owner or operator of pipeline facilities or is not in the public interest and a waiver of compliance with such standard is not inconsistent with pipeline safety, provided that such waiver shall not be effective until the requirements of 49 U.S.C.A. Section 2001, et seq. relative to such a waiver have first been satisfied.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2847 (December 2003).