Natural Gas Pipelines Safety Regulation

NGS 12/2024

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UTILITIES REGULATION & COMPETITION AUTHORITY
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Citation

This Regulation may be cited as the Safety Regulations for Natural Gas Pipelines, 2024.

1 Introduction

1.1 Scope and Objectives

1) In the exercise of the powers conferred upon it by section 8(3)(c) and 123(a) of the Natural Gas Act, 2024, the Utilities Regulation and Competition Authority ("URCA") hereby issues these Regulations relating to the safety standards for natural gas pipelines.

2) The objectives of this regulation are to prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Continental Shelf Act, Chapter 5 of the Statute Laws of The Bahamas.

1.2 Application

3) These Regulations shall apply to any person holding an Gas Transporter Licence.

1.3 Entry into effect

4) These Regulations shall come into effect on the date of their publication in accordance with section 15(1)(a) of the Natural Gas Act, 2024.

1.4 Definitions

5) In these Regulations, any word or expression to which a meaning has been assigned in the Natural Gas Act, 2024 has the meaning so assigned and, unless the context otherwise requires, the following terms will have the following meanings:

"**Abandoned**" means permanently removed from service.

"**Active Corrosion**" means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.

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

"**Close Interval Survey**" means a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.

"**Composite Materials**" means materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.

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

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

"**Customer Meter**" means the meter that measures the transfer of gas from an operator to a person who purchases it for consumption.

"Department of Environmental Planning and Protection (DEPP)" means the government agency responsible for overseeing environmental regulations, ensuring sustainable development, and protecting natural resources through planning, monitoring, and enforcement activities.

"**Distribution Center**" means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example:

a) At a metering location;

b) A pressure reduction location; or

c) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.

"**Distribution Line**" means a pipeline other than a transmission line.

"**Dry Gas Or Dry Natural Gas**" means gas above its dew point and without condensed liquids.

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

"**Engineering Critical Assessment (ECA)**" means a documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure.

"**Entirely Replaced Onshore Transmission Pipeline Segments**" means, for the purposes of sections 5.22 and 13.24, where 2 or more miles, in the aggregate, of onshore transmission pipeline have been replaced within any 5 contiguous miles of pipeline within any 24-month period.

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

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

“**Hard Spot**” means an area on steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV10).

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

“**High-Pressure Distribution System**” means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

“**In-line Inspection (ILI)”** means an inspection of a pipeline from the interior of the pipe using an inspection tool also called intelligent or smart pigging, including tethered and self-propelled inspection tools.

“**In-Line Inspection Tool Or Instrumented Internal Inspection Device**” means an instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an intelligent or smart pig.

“**Island**” means any of the geographically distinct land masses separated by a body of water and any of the islands within the Commonwealth of the Bahamas, including Paradise Island.

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

“**Listed Specification**” means a specification listed in section I of appendix A of this regulation.

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

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

“**Master meter**” means a type of gas distribution system where a single meter (the "master meter") measures the total gas usage for a large facility or a complex of buildings, such as an apartment complex, a mobile home park, or a university campus.

“**Maximum Actual Operating Pressure**” means the maximum pressure that occurs during normal operations over a period of 1 year.

“**Maximum Allowable Operating Pressure (MAOP)**” means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this regulation.

“Ministry of Public Works (MoPW)” means the government ministry that oversees public infrastructure, including the planning, construction, and maintenance of roads, buildings, and transportation systems, as well as the issuance of permits for vehicle operation and construction activities.

"**Moderate Consequence Area**" means:

a) An onshore area that is within a potential impact circle, as defined in section 16.2, containing either:

   i) Five (5) or more buildings intended for human occupancy; or

   ii) Any portion of the paved surface, including shoulders, of a road as defined in the Road Traffic Act, Chapter 220 of the Statute Laws of The Bahamas with 2 or more lanes, and that does not meet the definition of high consequence area, as defined in section 16.2.

   iii) Any portion of the paved surface, including shoulders, of a road as defined in the Road Traffic Act, Chapter 220 of the Statute Laws of The Bahamas with 2 or more lanes, and that does not meet the definition of high consequence area, as defined in section 16.2.

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

"**Notification Of Potential Rupture**" means the notification to, or observation by, an operator of indicia identified in section 13.24 of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline.

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

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

"**Outer Continental Shelf**" means all submerged lands lying seaward and outside the area of lands beneath the Territorial Sea as defined in Section 4 of the Archipelagic Waters and Maritime Jurisdiction Act, Chapter 282 of the Statute Laws of The Bahamas and of which the subsoil and seabed appertain to The Bahamas and are subject to its jurisdiction and control.

"**Person**" means any individual, firm, joint venture, partnership, corporation, company, association, , cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

"**Petroleum Gas**" means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 °F (38 °C).

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

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

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

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

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

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

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

"**SMYS**" means specified minimum yield strength is:

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

b) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with section 4.4, paragraph 60).

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

"The Bahamas" means all or any part of The Commonwealth of The Bahamas including the Port Area on the island of Grand Bahama;

"**Transmission Line**" means a pipeline or connected series of pipelines[1], that:

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

b) Has an MAOP of 20 percent or more of SMYS;

c) Transports gas within a storage field; or

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[1] A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

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

"**Transportation Of Gas**" means the transmission or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

"URCA" means the Utilities Regulation and Competition Authority as established under Section 3 of the Utilities Regulation and Competition Authority Act, 2009;

"URCA Act" means the Utilities Regulation and Competition Authority Act, 2009;

"**Underground natural gas storage facility**" (UNGSF) means a gas pipeline facility that stores natural gas underground incidental to the transportation of natural gas, including:

a)
  i) A depleted hydrocarbon reservoir;
  ii) An aquifer reservoir; or
  iii) A solution-mined salt cavern.

b) In addition to the reservoir or cavern, a UNGSF includes injection, withdrawal, monitoring, and observation wells; wellbores and downhole components; wellheads and associated wellhead piping; wing-valve assemblies that isolate the wellhead from connected piping beyond the wing-valve assemblies; and any other equipment, facility, right-of-way, or building used in the underground storage of natural gas.

"**Weak Link**" means a device or method used when pulling polyethylene pipe, typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stresses allowed.

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

"**Welding Operator**" means a person who operates machine or automatic welding equipment.

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

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

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

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

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

ii) Where:

1. D = Outside diameter of the pipe, in. (mm);
2. h = Crest-to-trough height of the ripple, in. (mm); and
3. S = Maximum operating hoop stress, psi (S/145, MPa).

1.5 Class locations

6) This section classifies pipeline locations for purposes of this regulation. The following criteria apply to classifications under this section.

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

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

7) Except as provided in paragraph 9) of this section, pipeline locations are classified as follows:

   a) A Class 1 location is:

      i) An offshore area; or

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

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

   c) A Class 3 location is:

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

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

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

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

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

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

9) An operator must have records that document the current class location of each gas transmission pipeline segment and that demonstrate how the operator determined each current class location in accordance with this section.

1.6 Interpretation

10) In these Regulations, unless the contrary appears:

a) headings are for convenience only and do not affect interpretation;

b) a reference to a statute or other law includes regulations and other instruments under it and consolidations, amendments, re-enactments or replacements of any of them;

c) words in the singular include the plural and vice versa;

d) words importing persons include a body whether corporate, politic, or otherwise;

e) where a word or phrase is defined, its other grammatical forms have a corresponding meaning;

f) mentioning anything after include, includes or including does not limit what else might be included;

g) words and expressions which are not defined have the meanings given to them in the Comms Act;

h) reference to a person shall include firms or companies; and

i) cross references are marked with an open parenthesis. It is expressly stated that the use of an open parenthesis in these cross references bears no legal interpretation. The sole legally pertinent element is the reference number.

1.7 List of documents incorporated by reference partly or wholly in this regulation

11) Certain material is incorporated by reference into this regulation with the approval of URCA. Any changes to these regulations will be made by URCA in accordance with its established Consultation Process. Changes to approved material will be made in accordance with the standards specified by the following institutions, said standards being incorporated by reference into these regulations.

	Subject Matter	**Document**	**Issuing Body**
a)	Recommended Practice for Truck Transportation of Line Pipe, applying to section 3.6.	API Recommended Practice 5LT, "Recommended Practice for Truck Transportation of Line Pipe," First edition, March 2012. Cited as: API RP 5LT.	American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: https://www.api.org/ .
b)	Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels, applying to section 3.6.	API Recommended Practice 5LW, "Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels," 3rd edition, September 2009. Cited as: API RP 5LW.	American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: https://www.api.org/ .
c)	Public Awareness	API Recommended Practice 1162,	American Petroleum Institute (API),

	Programs for Pipeline Operators, applying to section 13.11.	"Public Awareness Programs for Pipeline Operators," 1st edition, December 2003. Cited as: API RP 1162.	200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: https://www.api.org/ .
d)	Recommended Practice for Pipeline SCADA Displays, applying to section 13.21.	API Recommended Practice 1165, "Recommended Practice for Pipeline SCADA Displays," First edition, January 2007. Cited as: API RP 1165.	American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: https://www.api.org/ .
e)	Specification for Line Pipe, applying to sections 3.3, 4.7, 4.8 and 18.	API Specification 5L, "Specification for Line Pipe," 45th edition, effective July 1, 2013. Cited as: API Spec 5L.	American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: https://www.api.org/ .
f)	Specification for Pipeline Valves, applying to 5.4.	ANSI/API Specification 6D, "Specification for Pipeline Valves,"23rd edition, effective October 1, 2008, including Errata 1 (June 2008), Errata2 (/November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011) Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012). Cited as: ANSI/API Spec 6D.	American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: https://www.api.org/ .
g)	Welding of Pipelines and Related Facilities, applying to sections 6.2, 6.3, 6.4 and 6.8.	API Standard 1104, "Welding of Pipelines and Related Facilities," 20th edition, October 2005, including errata/addendum (July 2007) and errata 2 (2008). Cited as: API Std 1104.	American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: https://www.api.org/ .
h)	Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage, applying to section 2.3.	API Recommended Practice 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," First edition, July 2015. Cited as: API RP 1170.	American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: https://www.api.org/ .
i)	Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, applying to section 2.3.	API Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," First edition, September 2015. Cited as: API RP 1171.	American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: https://www.api.org/ .
j)	In-Line Inspection Systems Qualification, applying to section 10.25.	API STANDARD 1163, "In-Line Inspection Systems Qualification," Second edition, April 2013, Reaffirmed August 2018. Cited as: API STD 1163.	American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: https://www.api.org/ .
k)	Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250), applying to section	ASME/ANSI B16.1-2005, "Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)," August 31, 2006.	ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), http://www.asme.org/ .

	5.5.	Cited as: ASME/ANSI B16.1.	
l)	Pipe Flanges and Flanged Fittings, applying to sections 7.5 and 13.4.	ASME/ANSI B16.5-2003, "Pipe Flanges and Flanged Fittings," October 2004. Cited as: ASME/ANSI B16.5.	ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), http://www.asme.org/ .
m)	Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems, applying to section 18.	ASME B16.40-2008, "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems," March 18, 2008, approved by ANSI. Cited as: ASME B16.40-2008.	ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), http://www.asme.org/ .
n)	Manual for Determining the Remaining Strength of Corroded Pipelines, applying to sections 13.22 and 14.9.	ASME/ANSI B31G-1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004. Cited as: ASME/ANSI B31G.	ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), http://www.asme.org/ .
o)	Gas Transmission and Distribution Piping Systems, applying to sections 2.4, 14.11, 16.2, 16.4, 16.6, 16.7, 16.9, 16.11, 16.12, 16.13, 16.17, 16.19, 16.20 and 16.23.	ASME/ANSI B31.8-2007, "Gas Transmission and Distribution Piping Systems," November 30, 2007. Cited as: ASME/ANSI B31.8.	ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), http://www.asme.org/ .
p)	Supplement to B31.8 on Managing System Integrity of Gas Pipelines, applying to sections 2.4, 14.11, 16.2, 16.4, 16.6, 16.7, 16.9, 16.11, 16.12, 16.13, 16.17, 16.19, 16.20 and 16.23.	ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," approved January 14, 2005. Cited as: ASME/ANSI B31.8S.	ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), http://www.asme.org/ .
q)	Rules for Construction of Pressure Vessels, applying to sections 5.9, 6.2 and 6.3.	ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 "Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007. Cited as: ASME BPVC, Section VIII, Division 1.	ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), http://www.asme.org/ .
r)	Alternate Rules, Rules for Construction of Pressure Vessels, applying to sections 5.9, 6.2 and 6.3.	ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 "Alternate Rules, Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007. Cited as: ASME BPVC, Section VIII, Division 2.	ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), http://www.asme.org/ .
s)	Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators, applying to section 6.2.	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. Cited as: ASME BPVC, Section IX.	ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), http://www.asme.org/ .
t)	In-line Inspection Personnel Qualification	(ANSI/ASNT ILI-PQ-2005(2010), "In-line Inspection Personnel	1. American Society for Nondestructive Testing (ASNT), P.O.

	and Certification, applying to section 10.25.	Qualification and Certification," Reapproved October 11, 2010. Cited as: ANSI/ASNT ILI-PQ.	Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone: 800-222-2768, website: https://www.asnt.org/ .
u)	Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless, applying to section 18.	ASTM A53/A53M-10, "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless," approved October 1, 2010. Cited as: ASTM A53/A53M.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
v)	Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service, applying to section 4.8.	ASTM A106/A106M-10, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service," approved October 1, 2010. Cited as: ASTM A106/A106M.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
w)	Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service, applying to section 18.	ASTM A333/A333M-11, "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service," approved April 1, 2011. Cited as: ASTM A333/A333M.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
x)	Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels, applying to section 5.21.	ASTM A372/A372M-10, "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels," approved October 1, 2010. Cited as: ASTM A372/A372M.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
y)	Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems, applying to section 18.	ASTM A381-96 (reapproved 2005), "Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems," approved October 1, 2005. Cited as: ASTM A381.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
z)	Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications, applying to section 4.7.	ASTM A578/A578M-96 (reapproved 2001), "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications". Cited as: ASTM A578/A578M.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
aa)	Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures, applying to section 18	ASTM A671/A671M-10, "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures," approved April 1, 2010. Cited as: ASTM A671/A671M.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
bb)	Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures, applying to sections 4.8 and 18.	ASTM A672/A672M-09, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures," approved October 1, 2009. Cited as: ASTM A672/672M.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
cc)	Standard Specification	ASTM A691/A691M-09, "Standard	ASTM International (formerly

	for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures, applying to sections 4.8 and 18.	Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures," approved October 1, 2009. Cited as: ASTM A691/A691M.	American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
dd)	Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings, applying to section 18.	ASTM D2513-18a, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings," approved August 1, 2018. Cited as: ASTM D2513.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
ee)	Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings, applying to sections 7.6 and 18.	ASTM D2517-00, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings". Cited as: ASTM D 2517.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
ff)	Standard Specification for Solvent Cements for Poly (Vinyl Chloride) (PVC) Plastic Piping Systems, applying to section 7.6.	ASTM D2564-12, "Standard Specification for Solvent Cements for Poly (Vinyl Chloride) (PVC) Plastic Piping Systems," Aug. 1, 2012. Cited as: ASTM D2564-12.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
gg)	Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing, applying to section 18.	ASTM F1055-98 (Reapproved 2006), "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing," March 1, 2006. Cited as: ASTM F1055-98 (2006).	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
hh)	Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing, applying to section 18.	ASTM F1924-12, "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing," April 1, 2012. Cited as: ASTM F1924-12.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
ii)	Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing, applying to section 18.	ASTM F1948-12, "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing," April 1, 2012. Cited as: ASTM F1948-12.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
jj)	Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems,	ASTM F1973-13, "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems," May 1, 2013. Cited as: ASTM F1973-13	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .

	applying to sections 5.34 and 18.		
kk)	Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing, applying to section 18.	ASTM F2145-13, "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing," May 1, 2013. Cited as: ASTM F2145-13.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
ll)	Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing, applying to section 18.	ASTM F 2600-09, "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing," April 1, 2009. Cited as: ASTM F 2600-09, IBR approved for Item I, Appendix A to Part 192.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
mm)	Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings, applying to sections 7.6 and 7.8.	ASTM F2620-19, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings," approved February 1, 2019. Cited as: ASTM F2620.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
nn)	Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution, applying to section 18.	ASTM F2767-12, "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution," Oct. 15, 2012. Cited as: ASTM F2767-12.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
oo)	Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings, applying to section 18.	ASTM F2785-12, "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings," Aug. 1, 2012. Cited as: ASTM F2785-12.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
pp)	Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair, applying to section 18.	ASTM F2817-10, "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair," Feb. 1, 2010. Cited as: ASTM F2817-10.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
qq)	Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings, applying to section 18.	ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings," Nov. 27, 2012. Cited as: ASTM F2945-12a.	ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: http://astm.org .
rr)	Steel Pipeline Flanges, applying to section 5.5.	MSS SP-44-2010, Standard Practice, "Steel Pipeline Flanges," 2010 edition, (including Errata (May 20, 2011)). Cited as: MSS SP-44.	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/ .
ss)	In-Line Inspection of Pipelines, applying to sections 5.7 and 10.25.	NACE Standard Practice 0102-2010, "In-Line Inspection of Pipelines," Revised 2010-03-13. Cited as: NACE SP0102.	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/ .
tt)	Stress Corrosion Cracking (SCC) Direct Assessment Methodology, applying to sections 16.12 and 16.15.	(NACE SP0204-2008, Standard Practice, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology," reaffirmed September 18, 2008. Cited as: NACE SP0204.	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/ .
uu)	Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA) , applying to sections 16.12 and 16.14.	NACE SP0206-2006, Standard Practice, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)," approved December 1, 2006. Cited as: NACE SP0206.	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/ .
vv)	Pipeline External Corrosion Direct Assessment Methodology, applying to sections 8.10, 10.6, 16.12, 16.13, 16.16, 16.18 and 16.20.	ANSI/NACE SP0502-2010, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology," revised June 24, 2010. Cited as: NACE SP0502.	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/ .
ww)	Flammable and Combustible Liquids Code, applying to section 14.21.	NFPA-30 (2012), "Flammable and Combustible Liquids Code," 2012 edition, June 20, 2011, including Errata 30-12-1 (September 27, 2011) and Errata 30-12-2 (November 14, 2011). Cited as: NFPA-30.	National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984-7275, Web site: http://www.nfpa.org/ .
xx)	Liquefied Petroleum Gas Code (LP-Gas Code), applying to section 2.2	NFPA-58 (2004), "Liquefied Petroleum Gas Code (LP-Gas Code)." Cited as: NFPA-58.	National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984-7275, Web site: http://www.nfpa.org/ .
yy)	Utility LP-Gas Plant Code, applying to section 2.2	NFPA-59 (2004), "Utility LP-Gas Plant Code." Cited as: NFPA-59.	National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984-7275, Web site: http://www.nfpa.org/ .
zz)	National Electrical Code, applying to section 5.14 and 5.27.	NFPA-70 (2011), "National Electrical Code," 2011 edition, issued August 5, 2010. Cited as: NFPA-70.	National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984-7275, Web site: http://www.nfpa.org/ .
aaa)	Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design	PPI TR-3/2012, HDB/HDS/PDB/SDB/MRS/CRS, Policies, "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis	Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469-499-1044, http://www.plasticpipe.org/ .

	Basis (SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe, applying to section 4.10.	(SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe," updated November 2012, Cited as: PPI TR-3/2012.	
bbb)	PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Rating For Thermoplastic Piping Materials or Pipe, applying to section 4.10.	PPI TR-4, HDB/HDS/SDB/MRS, Listed Materials, "PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Rating For Thermoplastic Piping Materials or Pipe," updated March, 2011. Cited as: PPI TR-4/2012	Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469-499-1044, http://www.plasticpipe.org/ .
ccc)	Transportation of Hazardous Materials and Oil Transportation. Pipeline Safety. Part 191.	Transportation of Natural and Other Gas by Pipeline; Annual, Incident, and Other Reporting Cited as: US CFR 191	US Code of Federal Regulations. https://www.ecfr.gov/
ddd)	Pipelines. State pipeline safety program certifications and agreements. Compliance and waivers.	Pipelines. Cited as: U.S.C 49, 60105, 60106, 60118.	US Code (U.S.C). https://uscode.house.gov/

2 Specific provisions

2.1 Outer continental shelf pipelines

12) Operators of transportation pipelines on the Outer Continental Shelf (as defined in the Continental Shelf Act, Chapter 5 of the Statute Laws of The Bahamas) must identify on all their respective pipelines the specific points at which operating responsibility transfers to a producing operator. Where it is not practicable to durably mark a transfer point and the transfer point is located above water, the operator must depict the transfer point on a schematic located near the transfer point. Where a transfer point is located subsea, then the operator must identify the transfer point on a schematic which must be maintained at the nearest upstream facility and provided to URCA upon request. For those cases in which adjoining operators have not agreed on a transfer point the Regional Director and the MMS Regional Supervisor will make a joint determination of the transfer point.

2.2 Petroleum gas systems

13) A pipeline can only transport petroleum gas to a natural gas distribution system if it meets the requirements of this regulation and NFPA 58 and NFPA 59 (incorporated by reference).

14) Each pipeline system subject to this regulation that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this regulation and of ANSI/NFPA 58 and 59.

15) In the event of a conflict between this regulation and NFPA 58 and NFPA 59 (incorporated by

reference), NFPA 58 and NFPA 59 prevail.

2.3 Underground natural gas storage facilities

Underground natural gas storage facilities (UNGSFs), as defined in section 1.4, are not subject to any requirements of this regulation aside from this section.

16) **Salt cavern UNGSFs**

a) Each UNGSF that uses a solution-mined salt cavern for natural gas storage must meet all the provisions of API RP 1170 (incorporated by reference, see 1.7), the provisions of section 8 of API RP 1171 (incorporated by reference, see 1.7), that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraphs 18) and 19) of this section prior to commencing operations.

17) **Depleted hydrocarbon and aquifer reservoir UNGSFs.**

a) Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage must meet all provisions of API RP 1171 and paragraphs 18) and 19) of this section, prior to commencing operations.

18) **Procedural manuals.** Each operator of a UNGSF must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities under paragraphs 16) and 17) of this section. Each operator must keep records necessary to administer such procedures and review and update these manuals at intervals not exceeding 15 months, but at least once each calendar year. Each operator must keep the appropriate parts of these manuals accessible at locations where UNGSF work is being performed. Each operator must have written procedures in place before commencing operations or beginning an activity not yet implemented.

19) **Integrity management program —**

a) **Integrity management program elements.** The integrity management program for each UNGSF under this paragraph must consist, at a minimum, of a framework developed under API RP 1171, section 8 (“Risk Management for Gas Storage Operations”), and that also describes how relevant decisions will be made and by whom. An operator must make continual improvements to the program and its execution. The integrity management program must include the following elements:

i) A plan for developing and implementing each program element to meet the requirements of this section;

ii) An outline of the procedures to be developed;

iii) The roles and responsibilities of UNGSF staff assigned to develop and implement the procedures required by this paragraph;

iv) A plan for how staff will be trained in awareness and application of the procedures required by this paragraph;

v) Timelines for implementing each program element, including the risk analysis and baseline risk assessments; and

vi) A plan for how to incorporate information gained from experience into the integrity management program on a continuous basis.

b) **Integrity management baseline risk-assessment intervals.** Each UNGSF operator must complete the baseline risk assessments of all reservoirs and caverns, and at least 40% of the baseline risk assessments for each of its UNGSF wells (including wellhead assemblies), beginning with the highest-risk wells, as identified by the risk analysis process, prior to commencing operations. Furthermore, operators must complete baseline risk assessments on all their wells (including wellhead assemblies) within three years after the commencement of operations. Operators may use prior risk assessments for a well as a baseline (or part of the baseline) risk assessment in implementing its initial integrity management program, so long as the prior assessments meet the requirements of API RP 1171, section 8, and continue to be relevant and valid for the current operating and environmental conditions. When evaluating prior risk-assessment results, operators must account for the growth and effects of indicated defects since the time the assessment was performed.

c) **Integrity management re-assessment intervals.** The operator must determine the appropriate interval for risk assessments under API RP 1171, subsection 8.7.1, and this paragraph for each reservoir, cavern, and well, using the results from earlier assessments and updated risk analyses. The re-assessment interval for each reservoir, cavern, and well must not exceed seven years from the date of the baseline assessment for each reservoir, cavern, and well.

d) **Integrity management procedures and recordkeeping.** Each UNGSF operator must establish and follow written procedures to carry out its integrity management program under API RP 1171, section 8 ("Risk Management for Gas Storage Operations"), and this paragraph. The operator must also maintain, for the useful life of the UNGSF, records that demonstrate compliance with the requirements of this paragraph. This includes records developed and used in support of any identification, calculation, amendment, modification, justification, deviation, and determination made, and any action taken to implement and evaluate any integrity management program element.

2.4 General requirements that apply to pipelines regulated under this regulation

20) No person may operate a segment of pipeline that is readied for service, unless:

a) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this regulation; or

b) The pipeline qualifies for use under this regulation according to the requirements in section 2.5.

21) No person may operate a segment of pipeline that is replaced, relocated, or otherwise changed unless the replacement, relocation or change has been made according to the requirements in this regulation.

22) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this regulation.

23) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a management of change process. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11 (incorporated by reference, see section 1.7), that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff.

2.5 Conversion to service subject to this regulation.

24) A steel pipeline previously used in service not subject to this regulation qualifies for use under this regulation where the operator prepares and follows a written procedure to carry out the following requirements:

a) 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 where the pipeline is in a satisfactory condition for safe operation.

b) 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.

c) All known unsafe defects and conditions must be corrected in accordance with this regulation.

d) The pipeline must be tested in accordance with section 11 of this regulation to substantiate the maximum allowable operating pressure permitted by section 13.

25) 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 paragraph 24) of this section.

26) An operator converting a pipeline from service not previously covered by this regulation must notify URCA 60 calendar days before the conversion occurs.

2.6 Customer notification

27) This section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, where the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this section, “customer's buried piping” does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, “maintain” means monitor for corrosion according to section 10.8 where the customer's buried piping is metallic, survey for leaks according to section 14.17, and where an unsafe condition is found, shut off the flow

of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition.

28) Each operator shall notify each customer once in writing of the following information:

a) The operator does not maintain the customer's buried piping;

b) Where the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage;

c) Buried gas piping should be

i) Inspected for leaks, according to intervals set in section 10.8 ;

ii) Inspected for corrosion where the piping is metallic, according to intervals set in section 10.8;

iii) Repaired where any unsafe condition is discovered;

d) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand; and

e) The operator (where applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

29) Each operator shall notify each customer not later than 90 calendar days after the customer first receives gas at a particular location. However, operators of master meter systems may continuously post a general notice in a prominent location frequented by customers.

30) Each operator must make the following records available for inspection by URCA:

a) A copy of the notice currently in use; and

b) Evidence that notices have been sent to customers within the previous 3 years.

2.7 Notification to URCA

31) An operator must provide any notification required by this regulation by—

a) Sending the notification by electronic mail to Info@URCAbAHAMAS.BS with the subject matter *LNG Regulations*; or

b) Sending the notification by courier to ATTN: URCA Chief Executive Officer, Utilities Regulation and Competition Authority, Nassau, New Providence Bahamas

32) Unless otherwise specified, where an operator submits, pursuant to sections 2.4, 5.22, 8.10, 10.6, 11.4, 13.4, 13.12, 13.16, 13.21, 13.22, 13.24, 14.7, 14.9, 14.11, 14.27, 16.9, 16.11, 16.14, 16.17, or 16.19, a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (e.g., “other technology” or “alternative equivalent technology”) than otherwise prescribed in those sections, that notification must be submitted to URCA for review at least 90 calendar days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method,

approach, compliance timeline, or technique 91 calendar days after submitting the notification unless it receives a letter from URCA, that it objects to the proposal or that URCA requires additional time and/or more information to conduct its review.

3 Materials

3.1 Scope

33) This section prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

3.2 General

Materials for pipe and components must be:

34) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

35) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

36) Qualified in accordance with the applicable requirements of this section.

3.3 Steel pipe

37) New steel pipe is qualified for use under this regulation where:

a) It was manufactured in accordance with a listed specification;

b) It meets the requirements of:

i) Section II of appendix A to this regulation; or

ii) Where it was manufactured before November 12, 1970, either section II or III of appendix A to this regulation; or

c) It is used in accordance with paragraph 39) or 40) of this section.

38) Used steel pipe is qualified for use under this regulation where:

a) It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of appendix A to this regulation;

b) It meets the requirements of:

i) Section II of appendix A to this regulation; or

ii) Where it was manufactured before November 12, 1970, either section II or III of appendix A to this regulation;

c) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of appendix A to this regulation; or

d) It is used in accordance with paragraph 39) of this section.

39) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. (41 MPa) where no close coiling or close bending is to be done, where visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. Where it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of appendix A to this regulation.

40) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline in accordance with the same specification as the pipe used in constructing that segment of pipeline.

41) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Spec 5L (incorporated by reference, see section 1.7).

3.4 Plastic pipe

42) New plastic pipe is qualified for use under this regulation where:

a) It is manufactured in accordance with a listed specification;

b) It is resistant to chemicals with which contact may be anticipated; and

c) It is free of visible defects.

43) Used plastic pipe is qualified for use under this regulation where:

a) It was manufactured in accordance with a listed specification;

b) It is resistant to chemicals with which contact may be anticipated;

c) It has been used only in gas service;

d) Its dimensions are still within the tolerances of the specification to which it was manufactured; and

e) It is free of visible defects.

44) For the purpose of paragraphs 42) a) and 43) a) of this section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used where it:

a) Meets the strength and design criteria required of pipe included in that listed specification; and

b) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

45) Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015 used under this regulation.

3.5 Marking of materials

46) Each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured.

47) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

48) Where any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

3.6 Transportation of pipe

49) **Ship or barge**. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference, see section 1.7).

50) **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 section 1.7).

3.7 Material properties

51) An operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with sections 3.2 and 3.3. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.

52) Where operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with sections 3.2 and 3.3, operators must retain such records for the life of the pipeline.

53) Where an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of section 13.17 according to the terms of that section.

3.8 Storage and handling of plastic pipe and associated components

54) Each operator must have and follow written procedures for the storage and handling of plastic pipe and associated components that meet the applicable listed specifications.

4 Pipe Design

4.1 Scope

55) This section prescribes the minimum requirements for the design of pipe.

4.2 General

56) Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

4.3 Design formula for steel pipe

57) The design pressure for steel pipe is determined in accordance with the following formula:

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

P = Design pressure in pounds per square inch (kPa) gauge.
S = Yield strength in pounds per square inch (kPa) determined in accordance with section 4.4 .
D = Nominal outside diameter of the pipe in inches (millimeters).
t = Nominal wall thickness of the pipe in inches (millimeters). Where this is unknown, it is determined in accordance with 4.5. Additional wall thickness required for concurrent external loads in accordance with section 4.2 may not be included in computing design pressure.
F = Design factor determined in accordance with section 4.6.
E = Longitudinal joint factor determined in accordance with section 4.8.
T = Temperature derating factor determined in accordance with section 4.9.

58) Where steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph 56) of this section where the temperature of the pipe exceeds 900 °F (482 °C) at any time or is held above 600 °F (316 °C) for more than 1 hour.

4.4 Yield strength (S) for steel pipe.

59) For pipe that is manufactured in accordance with a specification listed in section I of appendix A of this regulation, the yield strength to be used in the design formula in section 4.5 is the SMYS stated in the listed specification, where that value is known.

60) For pipe that is manufactured in accordance with a specification not listed in section I of appendix A to this regulation or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in section 4.3 is one of the following:

a) Where the pipe is tensile tested in accordance with section II-D of appendix A to this regulation, the lower of the following:

i) 80 percent of the average yield strength determined by the tensile tests.

ii) The lowest yield strength determined by the tensile tests.

b) Where the pipe is not tensile tested as provided in paragraph a) of this section, 24,000 p.s.i. (165 MPa).

4.5 Nominal wall thickness (t) for steel pipe.

61) Where the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

62) However, where the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, 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 in the design formula in section 4.3 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

4.6 Design factor (F) for steel pipe.

63) Except as otherwise provided in paragraphs 64), 65), and 66) of this section, the design factor to be used in the design formula in section 4.3 is determined in accordance with the following table:

Class location	Design factor (*F*)
1	0.72
2	0.60
3	0.50
4	0.40

64) A design factor of 0.60 or less must be used in the design formula in section 4.3 for steel pipe in Class 1 locations that:

a) Crosses the right-of-way of an unimproved public road, without a casing;

b) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway or a public street;

c) Is supported by a vehicular, pedestrian, , or pipeline bridge; or

d) Is used in a fabricated assembly, (including separators, mainline valve assemblies, and cross-connections) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

65) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in section 4.3 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway and a public street.

66) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula

in section 4.3 for—

a) Steel pipe in a compressor station, regulating station, or measuring station; and

b) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

4.7 Additional design requirements for steel pipe using alternative maximum allowable operating pressure.

67) For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure (MAOP) calculated under section 13.14, a segment must meet the following additional design requirements. Records for alternative MAOP must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this design issue:	The pipeline segment must meet these additional requirements:
(a) General standards for the steel pipe	(1) The plate, skelp, or coil used for the pipe must be micro-alloyed, fine grain, fully killed, continuously cast steel with calcium treatment.
	(2) The carbon equivalents of the steel used for pipe must not exceed 0.25 percent by weight, as calculated by the Ito-Bessyo formula (Pcm formula) or 0.43 percent by weight, as calculated by the International Institute of Welding (IIW) formula.
	(3) The ratio of the specified outside diameter of the pipe to the specified wall thickness must be less than 100. The wall thickness or other mitigative measures must prevent denting and ovality anomalies during construction, strength testing and anticipated operational stresses.
	(4) The pipe must be manufactured using API Spec 5L, product specification level 2 (incorporated by reference, see section 1.7) for maximum operating pressures and minimum and maximum operating temperatures and other requirements under this section.
(b) Fracture control	(1) The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with:
	(i) API Spec 5L (incorporated by reference, see section 1.7); or
	(ii) American Society of Mechanical Engineers (ASME) B31.8 (incorporated by reference, see section 1.7); and
	(iii) Any correction factors needed to address pipe grades, pressures, temperatures, or gas compositions not expressly addressed in API Spec 5L , product specification level 2 or ASME B31.8 (incorporated by reference, see section 1.7).
	(2) Fracture control must:
	(i) Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures, gas compositions, pipe grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions, that the pipeline is expected to experience. Where these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline;
	(ii) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters;

To address this design issue:	The pipeline segment must meet these additional requirements:
	(iii) Ensure at least 99 percent probability of fracture arrest within eight pipe lengths with a probability of not less than 90 percent within five pipe lengths; and (iv) Include fracture toughness testing that is equivalent to that described in supplementary requirements SR5A, SR5B, and SR6 of API Specification 5L (incorporated by reference, see section 1.7) and ensures ductile fracture and arrest with the following exceptions: (A) The results of the Charpy impact test prescribed in SR5A must indicate at least 80 percent minimum shear area for any single test on each heat of steel; and (B) The results of the drop weight test prescribed in SR6 must indicate 80 percent average shear area with a minimum single test result of 60 percent shear area for any steel test samples. The test results must ensure a ductile fracture and arrest. (3)Where it is not physically possible to achieve the pipeline toughness properties of paragraphs (b)(1) and (2) of this section, additional design features, such as mechanical or composite crack arrestors and/or heavier walled pipe of proper design and spacing, must be used to ensure fracture arrest as described in paragraph (b)(2)(iii) of this section.
(c) Plate/coil quality control	(1) There must be an internal quality management program at all mills involved in producing steel, plate, coil, skelp, and/or rolling pipe to be operated at alternative MAOP. These programs must be structured to eliminate or detect defects and inclusions affecting pipe quality. (2) A mill inspection program or internal quality management program must include (i) and either (ii) or (iii): (i) An ultrasonic test of the ends and at least 35 percent of the surface of the plate/coil or pipe to identify imperfections that impair serviceability such as laminations, cracks, and inclusions. At least 95 percent of the lengths of pipe manufactured must be tested. For all pipelines designed after December 22, 2008, the test must be done in accordance with ASTM A578/A578M Level B, or API Spec 5L Paragraph 7.8.10 (incorporated by reference, see section 1.7) or equivalent method, and either (ii) A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process. Use of sulfur prints is not an equivalent method. The test must be carried out on the first or second slab of each sequence graded with an acceptance criteria of one or two on the Mannesmann scale or equivalent; or (iii) A quality assurance monitoring program implemented by the operator that includes audits of: (a) all steelmaking and casting facilities, (b) quality control plans and manufacturing procedure specifications, (c) equipment maintenance and records of conformance, (d) applicable casting superheat and speeds, and (e) centerline segregation monitoring records to ensure mitigation of centerline segregation during the continuous casting process.
(d) Seam quality control	(1) There must be a quality assurance program for pipe seam welds to assure tensile strength provided in API Spec 5L (incorporated by reference, see section 1.7) for appropriate grades. (2) There must be a hardness test, using Vickers (Hv10) hardness test method or equivalent test method, to assure a maximum hardness of 280 Vickers of the following: (i) A cross section of the weld seam of one pipe from each heat plus one pipe from each welding line per day; and (ii) For each sample cross section, a minimum of 13 readings (three for each heat

To address this design issue:	The pipeline segment must meet these additional requirements:
	affected zone, three in the weld metal, and two in each section of pipe base metal). (3) All of the seams must be ultrasonically tested after cold expansion and mill hydrostatic testing.
(e) Mill hydrostatic test	(1) All pipe to be used in a new pipeline segment must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds. (2) Pipe in operation must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 90 percent SMYS for 10 seconds. (3) Pipe in operation must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds. The test pressure may include a combination of internal test pressure and the allowance for end loading stresses imposed by the pipe mill hydrostatic testing equipment as allowed by "ANSI/API Spec 5L" (incorporated by reference, see section 1.7).
(f) Coating	(1) The pipe must be protected against external corrosion by a non-shielding coating. (2) Coating on pipe used for trenchless installation must be non-shielding and resist abrasions and other damage possible during installation. (3) A quality assurance inspection and testing program for the coating must cover the surface quality of the bare pipe, surface cleanliness and chlorides, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, coating thickness, holiday detection, and repair.
(g) Fittings and flanges	(1) There must be certification records of flanges, factory induction bends and factory weld ells. Certification must address material properties such as chemistry, minimum yield strength and minimum wall thickness to meet design conditions. (2)Where the carbon equivalents of flanges, bends and ells are greater than 0.42 percent by weight, the qualified welding procedures must include a pre-heat procedure. (3) Valves, flanges and fittings must be rated based upon the required specification rating class for the alternative MAOP.
(h) Compressor stations	(1) A compressor station must be designed to limit the temperature of the nearest downstream segment operating at alternative MAOP to a maximum of 120 degrees Fahrenheit (49 degrees Celsius) or the higher temperature allowed in paragraph (h)(2) of this section unless a long-term coating integrity monitoring program is implemented in accordance with paragraph (h)(3) of this section. (2)Where research, testing and field monitoring tests demonstrate that the coating type being used will withstand a higher temperature in long-term operations, the compressor station may be designed to limit downstream piping to that higher temperature. Test results and acceptance criteria addressing coating adhesion, cathodic disbondment, and coating condition must be provided URCA where the pipeline is in service at least 60 calendar days prior to operating above 120 degrees Fahrenheit (49 degrees Celsius). (3) Pipeline segments operating at alternative MAOP may operate at temperatures above 120 degrees Fahrenheit (49 degrees Celsius) where the operator implements a long-term coating integrity monitoring program. The monitoring program must include examinations using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or an equivalent method of monitoring coating integrity. An operator must specify the periodicity at which these examinations occur and criteria for repairing identified indications. An operator must submit its long-term coating integrity monitoring program to URCA before the pipeline segments may be operated

To address this design issue:	The pipeline segment must meet these additional requirements:
	at temperatures in excess of 120 degrees Fahrenheit (49 degrees Celsius

4.8 Longitudinal joint factor (E) for steel pipe.

68) The longitudinal joint factor to be used in the design formula in section 4.3 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A106/A106M	Seamless	1.00
ASTM A333/A333M	Seamless	1.00
	Electric resistance welded	1.00
ASTM A381	Double submerged arc welded	1.00
ASTM A671/A671M	Electric-fusion-welded	1.00
ASTM A672	Electric-fusion-welded	1.00
ASTM A691/A691M	Electric-fusion-welded	1.00
API Spec 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
Other	Pipe over 4 inches (102 millimeters)	.80
Other	Pipe 4 inches (102 millimeters) or less	.60

Where the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other."

4.9 Temperature derating factor (T) for steel pipe.

69) The temperature derating factor to be used in the design formula in section 4.3 is determined as follows:

Gas temperature in degrees Fahrenheit (Celsius)	Temperature derating factor (T)
250 °F (121 °C) or less	1.000
300 °F (149 °C)	0.967
350 °F (177 °C)	0.933
400 °F (204 °C)	0.900
450 °F (232 °C)	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

4.10 Design of plastic pipe.

70) **Design pressure**. The design pressure for plastic pipe is determined in accordance with either of the

following formulas:

$$P = 2S \frac{t}{(D-t)}(DF)$$

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

P = Design pressure, gage, psi (kPa).

S = For thermoplastic pipe, the hydrostatic design basis (HDB) is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2012, (incorporated by reference, see section 1.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa).

t = Specified wall thickness, inches (mm).

D = Specified outside diameter, inches (mm).

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

DF = Design Factor, a maximum of 0.32 unless otherwise specified for a particular material in this section

71) **General requirements for plastic pipe and components.**

a) Except as provided in paragraphs 72) through 75) of this section, the design pressure for plastic pipe may not exceed a gauge pressure of 100 psig (689 kPa) for pipe used in:

   i) Distribution systems; or

   ii) Transmission lines in Class 3 and 4 locations.

b) Plastic pipe may not be used where operating temperatures of the pipe will be:

   i) Below −20 °F (−29 °C), or below −40 °F (−40 °C) where all pipe and pipeline components whose operating temperature will be below −20 °F (−29 °C) have a temperature rating by the manufacturer consistent with that operating temperature; or

   ii) Above the temperature at which the HDB used in the design formula under this section is determined.

c) Unless specified for a particular material in this section, the wall thickness of plastic pipe may not be less than 0.062 inches (1.57 millimeters).

d) All plastic pipe must have a listed HDB in accordance with PPI TR-4/2012 (incorporated by reference, see section 1.7).

72) **Polyethylene (PE) pipe requirements.**

a) For PE pipe produced after July 14, 2004, but before January 22, 2019, a design pressure of up to 125 psig may be used, provided:

i) The material designation code is PE2406 or PE3408.

ii) The pipe has a nominal size (Iron Pipe Size (IPS) or Copper Tubing Size (CTS)) of 12 inches or less (above nominal pipe size of 12 inches, the design pressure is limited to 100 psig); and

iii) The wall thickness is not less than 0.062 inches (1.57 millimeters).

b) For PE pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

i) The design pressure does not exceed 125 psig;

ii) The material designation code is PE2708 or PE4710;

iii) The pipe has a nominal size (IPS or CTS) of 24 inches or less; and

iv) The wall thickness for a given outside diameter is not less than that listed in Table 1:

Table 1

PE pipe: minimum wall thickness and SDR values		
Pipe size (inches)	**Minimum wall thickness (inches)**	**Corresponding SDR (values)**
1⁄2″ CTS	0.090	7
1⁄2″ IPS	0.090	9.3
3⁄4″ CTS	0.090	9.7
3⁄4″ IPS	0.095	11
1″ CTS	0.099	11
1″ IPS	0.119	11
11⁄4″ IPS	0.151	11
11⁄2″ IPS	0.173	11
2″	0.216	11
3″	0.259	13.5
4″	0.265	17
6″	0.315	21
8″	0.411	21
10″	0.512	21
12″	0.607	21
16″	0.762	21
18″	0.857	21

PE pipe: minimum wall thickness and SDR values		
Pipe size (inches)	**Minimum wall thickness (inches)**	**Corresponding SDR (values)**
20″	0.952	21
22″	1.048	21
24″	1.143	21

73) **Polyamide (PA-11) pipe requirements.**

a) For PA-11 pipe produced after January 23, 2009, but before January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

i) The design pressure does not exceed 200 psig;

ii) The material designation code is PA32312 or PA32316;

iii) The pipe has a nominal size (IPS or CTS) of 4 inches or less; and

iv) The pipe has a standard dimension ratio of SDR-11 or less (i.e., thicker wall pipe).

b) For PA-11 pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

i) The design pressure does not exceed 250 psig;

ii) The material designation code is PA32316;

iii) The pipe has a nominal size (IPS or CTS) of 6 inches or less; and

iv) The minimum wall thickness for a given outside diameter is not less than that listed in Table 2

Table 2

PA-11 pipe: minimum wall thickness and SDR values		
Pipe size (inches)	**Minimum wall thickness (inches)**	**Corresponding SDR (values)**
1⁄2″ CTS	0.090	7.0
1⁄2″ IPS	0.090	9.3
3⁄4″ CTS	0.090	9.7
3⁄4″ IPS	0.095	11
1″ CTS	0.099	11
1″ IPS	0.119	11
11⁄4 IPS	0.151	11
11⁄2″ IPS	0.173	11
2″ IPS	0.216	11
3″ IPS	0.259	13.5
4″ IPS	0.333	13.5

PA-11 pipe: minimum wall thickness and SDR values		
Pipe size (inches)	**Minimum wall thickness (inches)**	**Corresponding SDR (values)**
6″ IPS	0.491	13.5

74) **Polyamide (PA-12) pipe requirements.** For PA-12 pipe produced after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

a) The design pressure does not exceed 250 psig;

b) The material designation code is PA42316;

c) The pipe has a nominal size (IPS or CTS) of 6 inches or less; and

d) The minimum wall thickness for a given outside diameter is not less than that listed in Table 3:

Table 3

PA-12 pipe: minimum wall thickness and SDR values		
Pipe size (inches)	**Minimum wall thickness (inches)**	**Corresponding SDR (values)**
1⁄2″ CTS	0.090	7
1⁄2″ IPS	0.090	9.3
3⁄4″ CTS	0.090	9.7
3⁄4″ IPS	0.095	11
1″ CTS	0.099	11
1″ IPS	0.119	11
11⁄4″ IPS	0.151	11
11⁄2″ IPS	0.173	11
2″ IPS	0.216	11
3″ IPS	0.259	13.5
4″ IPS	0.333	13.5
6″ IPS	0.491	13.5

75) **Reinforced thermosetting plastic pipe requirements.**

a) Reinforced thermosetting plastic pipe may not be used at operating temperatures above 150 °F (66 °C).

b) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches (millimeters)	Minimum wall thickness in inches (millimeters)
2 (51)	0.060 (1.52)

Nominal size in inches (millimeters)	Minimum wall thickness in inches (millimeters)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

4.11 Design of copper pipe.

76) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.

77) Copper pipe used in service lines must have wall thickness not less than that indicated in the following table:

Standard size inch (millimeter)	Nominal O.D. inch (millimeter)	Wall thickness inch (millimeter)	
		Nominal	Tolerance
1⁄2 (13)	.625 (16)	.040 (1.06)	.0035 (.0889)
5⁄8 (16)	.750 (19)	.042 (1.07)	.0035 (.0889)
3⁄4 (19)	.875 (22)	.045 (1.14)	.004 (.102)
1 (25)	1.125 (29)	.050 (1.27)	.004 (.102)
11⁄4 (32)	1.375 (35)	.055 (1.40)	.0045 (.1143)
11⁄2 (38)	1.625 (41)	.060 (1.52)	.0045 (.1143)

78) Copper pipe used in mains and service lines may not be used at pressures in excess of 100 p.s.i. (689 kPa) gage.

79) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft3 (6.9/m3) under standard conditions. Standard conditions refers to 60 °F and 14.7 psia (15.6 °C and one atmosphere) of gas.

4.12 Records: Pipe design.

80) An operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with section 4.2 and documenting that the determination of design pressure for the pipe is made in accordance with section 4.3.

81) Where operators have records documenting pipe design and the determination of design pressure in accordance with sections 4.2 and 4.3, operators must retain such records for the life of the pipeline.

82) Where an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of section 13.17 according to the terms of that section.

5 Design of Pipeline Components

5.1 Scope.

83) This section prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

5.2 General requirements.

84) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, where design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

85) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in section 10 of this regulation.

86) Except for excess flow valves, each plastic pipeline component must be able to withstand operating pressures and other anticipated loads in accordance with a listed specification.

5.3 Qualifying metallic components.

Notwithstanding any requirement of this section which incorporates by reference an edition of a document listed in section 1.7 or Appendix A of this regulation, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this regulation if:

87) 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

88) 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 section 1.7 or appendix A of this regulation:

    a) Pressure testing;

    b) Materials; and

    c) Pressure and temperature ratings.

5.4 Valves.

89) Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Spec 6D (incorporated by reference, see section 1.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

90) Each cast iron and plastic valve must comply with the following:

a) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

b) The valve must be tested as part of the manufacturing, as follows:

i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating;

ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted; and

iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

91) Each valve must be able to meet the anticipated operating conditions.

92) No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, where:

a) The temperature-adjusted service pressure does not exceed 1,000 p.s.i. (7 Mpa) gage; and

b) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

93) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.

94) Except for excess flow valves, plastic valves must meet the minimum requirements of a listed specification. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in the listed specification.

5.5 Flanges and flange accessories.

95) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ ANSI B 16.5 and MSS SP-44 (incorporated by reference, see section 1.7), or the equivalent.

96) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

97) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 (incorporated by reference, see section 1.7) and be cast integrally with

the pipe, valve, or fitting.

5.6 Standard fittings.

98) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this regulation, or their equivalent.

99) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

100) Plastic fittings must meet a listed specification.

5.7 Passage of internal inspection devices.

101) Except as provided in paragraphs 102) and 103) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line, must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference, see section 1.7).

102) This section does not apply to:

a) Manifolds;

b) Station piping such as at compressor stations, meter stations, or regulator stations;

c) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

d) Cross-overs;

e) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

f) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

g) Offshore transmission lines, except transmission lines $10_{3/4}$ inches (273 millimeters) or more in outside diameter on which construction begins after December 28, 2005, that run from platform to platform or platform to shore unless—

i) Platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices; or

ii) Where the design includes taps for lateral connections, the operator can demonstrate, based on investigation or experience, that there is no reasonably practical alternative under the design circumstances to the use of a tap that will obstruct the passage of instrumented internal inspection devices;

h) Other piping that URCA finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

103) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph 101) of this section, where the operator determines and documents why an impracticability prohibits compliance with paragraph 101) of this section. Within thirty (30) calendar days after discovering the emergency or construction problem the operator must petition for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. Where the petition is denied, within one (1) year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

5.8 Tapping.

104) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

105) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

106) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that

a) Existing taps may be used for replacement service, where they are free of cracks and have good threads; and

b) A 11⁄4-inch (32 millimeters) tap may be made in a 4-inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement.

107) However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch (152 millimeters) or larger pipe.

5.9 Components fabricated by welding.

108) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, see section 1.7).

109) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with the ASME BPVC (Rules for Construction of Pressure Vessels as defined in either Section VIII, Division 1 or Section VIII, Division 2; incorporated by reference, see section 1.7), except for the following:

a) Regularly manufactured butt-welding fittings.

b) Pipe that has been produced and tested under a specification listed in appendix A to this regulation.

c) Partial assemblies such as split rings or collars.

d) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

110) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

111) Except for flat closures designed in accordance with the ASME BPVC (Section VIII, Division 1 or 2) (incorporated by reference, see section 1.7), flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage or more, or is more than 3 inches in (76 millimeters) nominal diameter.

112) The test requirements for a prefabricated unit or pressure vessel, defined for this paragraph as components with a design pressure established in accordance with paragraph 108) or paragraph 109) of this section are as follows.

a) A prefabricated unit or pressure vessel must be tested for the duration specified in either section 11.3, paragraph 441) or 442), section 11.5, paragraph 447), or section 11.6, paragraph 451) whichever is applicable for the pipeline in which the component is being installed.

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

i) Test the prefabricated unit or pressure vessel in accordance with this section and section 11 of this regulation after it has been placed on its support structure at its final installation location. The test may be performed before or after it has been tied-in to the pipeline. Test records that meet section 11.10, paragraph 462) must be kept for the operational life of the prefabricated unit or pressure vessel; or

ii) For a prefabricated unit or pressure vessel that is pressure tested prior to installation or where a manufacturer's pressure test is used in accordance with paragraph 112) of this section, inspect the prefabricated unit or pressure vessel after it has been placed on its support structure at its final installation location and confirm that the prefabricated unit or pressure vessel was not damaged during any prior operation, transportation, or installation into the pipeline. The inspection procedure and documented inspection must include visual inspection for vessel damage, including, at a minimum, inlets, outlets, and lifting locations. Injurious defects that are an integrity threat may include dents, gouges, bending, corrosion, and cracking. This inspection must be performed prior to operation but may be performed either before or after it has been tied-in to the pipeline. Where injurious defects that are an integrity threat are found, the prefabricated unit or pressure vessel must be either non-destructively tested, re-pressure tested, or remediated in accordance with requirements for a fabricated unit or with the applicable ASME BPVC requirements referenced in paragraphs 108) or 109) of this section. Test, inspection, and repair records for the fabricated unit or pressure vessel must be kept for the operational life of the component. Test records must meet the requirements in section 11.9, paragraph 462).

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

   i) The prefabricated unit or pressure vessel is newly-manufactured.

   ii) An initial pressure test from the fabricated unit or pressure vessel manufacturer or other prior test of a new or existing prefabricated unit or pressure vessel may be used for a component that is temporarily installed in a pipeline facility in order to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement. The temporary component must be promptly removed after that task is completed. Where operational and environmental constraints require leaving a temporary prefabricated unit or pressure vessel under this paragraph in place for longer than thirty (30) calendar days, the operator must notify URCA, as applicable, in accordance with section 2.7.

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

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

d) An existing prefabricated unit or pressure vessel that is temporarily removed from a pipeline facility to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement, and then re-installed at the same location must be inspected in accordance with paragraph b) ii) of this section; however, a new pressure test is not required provided no damage or threats to the operational integrity of the prefabricated unit or pressure vessel were identified during the inspection and the MAOP of the pipeline is not increased.

e) Except as provided in paragraphs c) ii) and iv) of this section, an existing prefabricated unit or pressure vessel relocated and operated at a different location must meet the requirements of this regulation and the following:

   i) The prefabricated unit or pressure vessel must be designed and constructed in accordance with the requirements of this regulation at the time the vessel is returned to operational service at the new location; and

   ii) The prefabricated unit or pressure vessel must be pressure tested by the operator in accordance with the testing and inspection requirements of this regulation applicable to newly installed prefabricated units and pressure vessels.

5.10 Welded branch connections.

113) Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

5.11 Extruded outlets.

114) Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

5.12 Flexibility.

115) Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

5.13 Supports and anchors.

116) Each pipeline and its associated equipment must have enough anchors or supports to:

a) Prevent undue strain on connected equipment;

b) Resist longitudinal forces caused by a bend or offset in the pipe; and

c) Prevent or damp out excessive vibration.

117) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

118) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

a) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

b) Provision must be made for the service conditions involved.

c) Movement of the pipeline may not cause disengagement of the support equipment.

119) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

a) A structural support may not be welded directly to the pipe.

b) The support must be provided by a member that completely encircles the pipe.

c) Where an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

120) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

121) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

5.14 Compressor stations: Design and construction.

122) **Location of compressor building.** Except for a compressor building on a platform located offshore or in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

123) **Building construction**. Each building on a compressor station site must be made of noncombustible materials where it contains either:

a) Pipes more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or

b) Gas handling equipment other than gas utilization equipment used for domestic purposes.

124) **Exits**. Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

125) **Fenced areas**. Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

126) **Electrical facilities**. Electrical equipment and wiring installed in compressor stations must conform to the NFPA-70 (incorporated by reference, see section 1.7), so far as that code is applicable.

5.15 Compressor stations: Liquid removal.

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

128) Each liquid separator used to remove entrained liquids at a compressor station must:

a) Have a manually operable means of removing these liquids.

b) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and

c) Be manufactured in accordance with section VIII ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see section 1.7) and the additional requirements of section 5.9, paragraph 112) except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

5.16 Compressor stations: Emergency shutdown.

129) Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:

a) It must be able to block gas out of the station and blow down the station piping.

b) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.

c) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except that:

i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and

ii) Electrical circuits needed to protect equipment from damage may remain energized.

d) It must be operable from at least two locations, each of which is:

i) Outside the gas area of the station;

ii) Near the exit gates, where the station is fenced, or near emergency exits, where not fenced; and

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

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

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

a) In the case of an unattended compressor station:

i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or

ii) When an uncontrolled fire occurs on the platform; and

b) In the case of a compressor station in a building:

i) When an uncontrolled fire occurs in the building; or

ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition.

132) For the purpose of paragraph 131) b) ii) of this section, an electrical facility which conforms to Class 1, Group D, of the National Electrical Code is not a source of ignition.

5.17 Compressor stations: Pressure limiting devices.

133) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.

134) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

5.18 Compressor stations: Additional safety equipment.

135) Each compressor station must have adequate fire protection facilities. Where fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

136) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

137) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

138) Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

139) Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

5.19 Compressor stations: Ventilation.

140) Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

5.20 Pipe-type and bottle-type holders.

141) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder.

142) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

C = (3D*P*F)/1000) in inches; (C = (3D*P*F*)/6,895) in millimeters in which:

C = Minimum clearance between pipe containers or bottles in inches (millimeters).

D = Outside diameter of pipe containers or bottles in inches (millimeters).

P = Maximum allowable operating pressure, psi (kPa) gauge.

F = Design factor as set forth in section 4.6 of this regulation.

5.21 Additional provisions for bottle-type holders.

143) Each bottle-type holder must be—

a) Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum allowable operating pressure	Minimum clearance feet (meters)
Less than 1,000 p.s.i. (7 MPa) gage	25 (7.6)
1,000 p.s.i. (7 MPa) gage or more	100 (31)

b) Designed using the design factors set forth in section 4.6; and

c) Buried with a minimum cover in accordance with section 8.14.

144) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

a) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/372M (incorporated by reference, see section 1.7).

b) The actual yield-tensile ratio of the steel may not exceed 0.85.

c) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection where a localized thermit welding process is used.

d) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.

e) The holder, connection pipe, and components must be leak tested after installation as required by section 11 of this regulation.

5.22 Transmission line valves.

145) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case URCA finds that alternative spacing would provide an equivalent level of safety.

a) Each point on the pipeline in a Class 4 location must be within 21⁄2 miles (4 kilometers) of a valve.

b) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.

c) Each point on the pipeline in a Class 2 location must be within 71⁄2 miles (12 kilometers) of a valve.

d) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

146) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

a) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

b) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

147) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, where the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

148) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency.

149) For onshore transmission pipeline segments with diameters greater than or equal to 6 inches, the operator must install rupture mitigation valves (RMV) or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify URCA in accordance with the procedures set forth in paragraph 151) of this section. All RMVs and alternative equivalent technologies installed pursuant to this paragraph must meet the requirements of section 13.25. The installation requirements in this paragraph do not apply to pipe segments with a potential impact radius (PIR), as defined in 16.2, that is less than or equal to 150 feet in either Class 1 or Class 2 locations. An operator may request an extension of the installation compliance deadline requirements of this paragraph where it can demonstrate to URCA, in accordance with the notification procedures in 2.7, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular new pipeline.

150) For entirely replaced onshore transmission pipeline segments, as defined in section 1.4, with diameters greater than or equal to 6 inches, the operator must install RMVs or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify URCA in accordance with the procedures set forth in paragraph 151) of this section. All RMVs and alternative equivalent technologies installed pursuant to this paragraph must meet the requirements of section 13.25. The requirements of this paragraph apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. The installation requirements in this paragraph do not apply to pipe segments with a PIR, as defined in section 16.2, that is less than or equal to 150 feet in either Class 1 or Class 2 locations. An operator

may request an extension of the installation compliance deadline requirements of this paragraph where it can demonstrate to URCA in accordance with the notification procedures in section 2.7, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular pipeline replacement project.

151) Where an operator elects to use alternative equivalent technology in accordance with paragraph 149) or 150) of this section, the operator must notify URCA in accordance with the procedures in section 2.7. The operator must include a technical and safety evaluation in its notice to URCA Valves that are installed as alternative equivalent technology must comply with sections 13.23 and 13.25. An operator requesting use of manual valves as an alternative equivalent technology must also include within the notification submitted to URCA demonstration that installation of an RMV as otherwise required would be economically, technically, or operationally infeasible. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, and use of such valve would not require a notification to URCA in accordance with section 2.7, but it must comply with section 13.25.

152) The valve spacing requirements of paragraph 145) of this section do not apply to pipe replacements on a pipeline where the distance between each point on the pipeline and the nearest valve does not exceed:

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

b) Seven-and-a-half (71⁄2) miles in Class 3 locations, with a total spacing between valves no greater than 15 miles; or

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

5.23 Distribution line valves.

153) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

154) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

155) Each valve on a main installed for operating or emergency purposes must comply with the following:

a) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

b) The operating stem or mechanism must be readily accessible.

c) Where the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

5.24 Vaults: Structural design requirements.

156) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

157) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

158) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inch (254 millimeters), and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.

5.25 Vaults: Accessibility.

159) Each vault must be located in an accessible location and, so far as practical, away from:

a) Street intersections or points where traffic is heavy or dense;

b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and

c) Water, electric, steam, or other facilities.

5.26 Vaults: Sealing, venting, and ventilation.

Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows:

160) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):

a) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;

b) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

c) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

161) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):

a) Where the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;

b) Where the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

c) Where the vault or pit is ventilated, paragraph 160) or 162) of this section applies.

162) Where a vault or pit covered by paragraph 161) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

5.27 Vaults: Drainage and waterproofing.

163) Each vault must be designed so as to minimize the entrance of water.

164) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

165) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, NFPA-70 (incorporated by reference, see section 1.7).

5.28 Valve installation in plastic pipe.

166) Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

5.29 Protection against accidental overpressuring.

167) General requirements. Except as provided in section 5.30 each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of sections 5.31 and 5.32.

168) Additional requirements for distribution systems. Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

a) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

b) Be designed so as to prevent accidental over-pressuring.

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

169) Where the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less and a service regulator having the following characteristics is used, no other pressure limiting device is required:

a) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.

b) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

c) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.

d) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.

e) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

f) A self-contained service regulator with no external static or control lines.

170) Where the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph 169) of this section is used, or where the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe over-pressuring of the customer's appliances where the service regulator fails.

171) Where the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

a) A service regulator having the characteristics listed in paragraph 169) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i. (414 kPa) gage. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i. (414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, where the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i. (414 kPa) gage or less), and remains closed until manually reset.

b) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

c) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i. (862 kPa) gage. For higher inlet pressures, the methods in paragraphs a) or b) of this section must be used.

d) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

5.31 Requirements for design of pressure relief and limiting devices.

Except for rupture discs, each pressure relief or pressure limiting device must:

172) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

173) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

174) Be designed and installed so that it can be readily operated to determine where the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

175) Have support made of noncombustible material;

176) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

177) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

178) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

179) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

5.32 Required capacity of pressure relieving and limiting stations.

180) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

a) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

b) In pipelines other than a low pressure distribution system:

i) Where the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

ii) Where the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. (41 kPa) gage; or

    iii) Where the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

181) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

182) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

5.33 Instrument, control, and sampling pipe and components.

183) **Applicability**. This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

184) **Materials and design**. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

a) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

b) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

c) Brass or copper material may not be used for metal temperatures greater than 400 °F (204 °C).

d) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

e) Pipe or components in which liquids may accumulate must have drains or drips.

f) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

g) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

h) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

i) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

5.34 Risers installed.

185) Riser designs must be tested to ensure safe performance under anticipated external and internal loads acting on the assembly.

186) Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973-13 (incorporated by reference, see section 1.7).

187) All risers used to connect regulator stations to plastic mains must be rigid and designed to provide adequate support and resist lateral movement. Anodeless risers used in accordance with this paragraph must have a rigid riser casing.

5.35 Records: Pipeline components.

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

189) Where operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline.

190) Where an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of section 13.17 according to the terms of that section.

6 Welding of Steel in Pipelines

6.1 Scope.

191) This section prescribes minimum requirements for welding steel materials in pipelines.

192) This section does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

6.2 Welding procedures.

193) 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 section 1.7), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see section 1.7) to produce welds meeting the requirements of this section. The quality of the test welds used to qualify welding procedures must be determined by destructive testing in accordance with the applicable welding standard(s).

194) 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.

6.3 Qualification of welders and welding operators.

195) Except as provided in paragraph 196) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see section 1.7), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see section 1.7). However, a welder or welding operator qualified under an earlier edition than the listed in section 1.7 of this regulation may weld but may not requalify under that earlier edition.

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

197) Records demonstrating each individual welder qualification at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

6.4 Limitations on welders and welding operators.

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

199) A welder or welding operator may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder or welding operator was engaged in welding with that process. Alternatively, welders or welding operators may demonstrate they have engaged in a specific welding process where they have performed a weld with that process that was tested and found

acceptable under section 6, 9, 12, or Appendix A of API Std 1104 (incorporated by reference, see section 1.7) within the preceding 71⁄2 months.

200) A welder or welding operator qualified under —paragraph 195)

a) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder or welding operator has had one weld tested and found acceptable under either section 6, section 9, section 12 or Appendix A of API Std 1104 (incorporated by reference, see section 1.7). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 71⁄2 months. A welder or welding operator qualified under an earlier edition of a standard listed in section 1.7 of this regulation may weld, but may not re-qualify under that earlier edition; and,

b) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder or welding operator is tested in accordance with paragraph a) of this section or re-qualifies under paragraph 201) a) or 201) b) of this section.

201) A welder or welding operator qualified under section 6.3, paragraph 196) may not weld unless—

a) Within the preceding 15 calendar months, but at least once each calendar year, the welder or welding operator has re-qualified under section 6.3, paragraph 196); or

b) Within the preceding 7 1⁄2 calendar months, but at least twice each calendar year, the welder or welding operator has had—

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

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

6.5 Protection from weather.

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

6.6 Miter joints.

203) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.

204) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 121⁄2° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

205) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

6.7 Preparation for welding.

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

6.8 Inspection and test of welds.

207) Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that:

a) The welding is performed in accordance with the welding procedure; and

b) The weld is acceptable under paragraph 209) of this section.

208) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with section 6.9, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested where:

a) The pipe has a nominal diameter of less than 6 inches (152 millimeters); or

b) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

209) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 9 or Appendix A of API Std 1104 (incorporated by reference, see section 1.7). Appendix A of API Std 1104 may not be used to accept cracks.

6.9 Nondestructive testing.

210) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.

211) Nondestructive testing of welds must be performed:

a) In accordance with written procedures; and

b) By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

212) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under section 6.8, paragraph 209).

213) When nondestructive testing is required under section 6.8, paragraph 209), the following percentages of each day's field butt welds, selected at random by the operator, must be

nondestructively tested over their entire circumference:

a) In Class 1 locations, except offshore, at least 10 percent.

b) In Class 2 locations, at least 15 percent.

c) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

d) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

214) Except for a welder or welding operator whose work is isolated from the principal welding activity, a sample of each welder or welding operator's work for each day must be nondestructively tested, when nondestructive testing is required under section 6.8, paragraph 208).

215) When nondestructive testing is required under section 6.8, paragraph 208) each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

6.10 Repair or removal of defects.

216) Each weld that is unacceptable under section 6.8, paragraph 209) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed where it has a crack that is more than 8 percent of the weld length.

217) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated where 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.

218) 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 section 6.2. 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.

7 Joining of Materials Other Than by Welding

7.1 Scope.

219) This section prescribes minimum requirements for joining materials in pipelines, other than by welding.

220) This section does not apply to joining during the manufacture of pipe or pipeline components.

7.2 General.

221) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

222) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

223) Each joint must be inspected to insure compliance with this section.

7.3 Cast iron pipe.

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

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

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

227) Cast iron pipe may not be joined by brazing.

7.4 Ductile iron pipe.

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

229) Ductile iron pipe may not be joined by brazing.

7.5 Copper pipe.

230) Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded where the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5 (incorporated by reference, see section 1.7).

7.6 Plastic pipe.

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

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

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

b) The solvent cement must conform to ASTM D2564-12 for PVC (incorporated by reference, see section 1.7).

c) The joint may not be heated or cooled to accelerate the setting of the cement.

233) **Heat-fusion joints**. Each heat fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620 (incorporated by reference in section 1.7), or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by test or experience to produce strong gastight joints, and the following:

a) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the pipe or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under section 7.7.

b) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the pipe or component, uniformly and simultaneously, to establish the same temperature. The device used must be the same device specified in the operator's joining procedure for socket fusion.

c) An electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer, or using equipment and techniques shown, by testing joints to the requirements of section 7.7, paragraph 236) a) iii), to be equivalent to or better than the requirements of the fitting manufacturer.

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

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

a) The adhesive must conform to ASTM D 2517 (incorporated by reference, see section 1.7).

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

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

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

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

c) All mechanical fittings must meet a listed specification based upon the applicable material.

d) All mechanical joints or fittings installed must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area where tested in accordance with the applicable standard.

7.7 Plastic pipe: Qualifying joining procedures.

236) **Heat fusion, solvent cement, and adhesive joints**. Before any written procedure established under section 7.2, paragraph 222), is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints that are made according to the procedure to the following tests, as applicable:

a) The test requirements of—

i) In the case of thermoplastic pipe, based on the pipe material, the Sustained Pressure Test or the Minimum Hydrostatic Burst Test per the listed specification requirements. Additionally, for electrofusion joints, based on the pipe material, the Tensile Strength Test or the Joint Integrity Test per the listed specification.

ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517- 00 (incorporated by reference, see section 1.7).

iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055-98(2006) (incorporated by reference, see section 1.7).

b) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. Where failure initiates outside the joint area, the procedure qualifies for use.

c) For procedures intended for non-lateral pipe connections, perform tensile testing in accordance with a listed specification. Where the test specimen elongates no less than 25% or failure initiates outside the joint area, the procedure qualifies for use.

237) **Mechanical joints.** Before any written procedure established under section 7.2, paragraph 222) is used for making mechanical plastic pipe joints, the procedure must be qualified in accordance with a listed specification based upon the pipe material.

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

7.8 Plastic pipe: Qualifying persons to make joints.

239) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

a) Appropriate training or experience in the use of the procedure; and

b) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph 240) of this section.

240) The specimen joint must be:

a) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

b) In the case of a heat fusion, solvent cement, or adhesive joint:

i) Tested under any one of the test methods listed under section 7.7, paragraph 236), and for PE heat fusion joints (except for electrofusion joints) visually inspected in accordance with ASTM F2620 (incorporated by reference, see section 1.7), or a written procedure that has been demonstrated to provide an equivalent or superior level of safety, applicable to the type of joint and material being tested;

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

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

1. Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

2. Deformed by bending, torque, or impact, and where failure occurs, it must not initiate in the joint area.

241) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under section 11.8.

242) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.

243) Records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

7.9 Plastic pipe: Inspection of joints.

244) No person may carry out the inspection of joints in plastic pipes required by sections 7.2, paragraph 223) and 7.8, paragraph 240) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

8 General Construction Requirements for Transmission Lines and Main

8.1 Scope.

245) This section prescribes minimum requirements for constructing transmission lines and mains.

8.2 Compliance with specifications or standards.

246) Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this regulation.

8.3 Inspection: General.

247) Each transmission line or main must be inspected to ensure that it is constructed in accordance with this regulation.

8.4 Inspection of materials.

248) Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

8.5 Repair of steel pipe.

249) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. Where a repair is made by grinding, the remaining wall thickness must at least be equal to either:

a) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

b) The nominal wall thickness required for the design pressure of the pipeline.

250) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

a) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.

b) A dent that affects the longitudinal weld or a circumferential weld.

c) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

i) More than 1⁄4 inch (6.4 millimeters) in pipe 123⁄4 inches (324 millimeters) or less in outer diameter; or

ii) More than 2 percent of the nominal pipe diameter in pipe over 123⁄4 inches (324 millimeters) in outer diameter. For the purpose of this section a “dent” is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

251) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. Where a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

a) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

b) The nominal wall thickness required for the design pressure of the pipeline.

252) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

253) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

8.6 Repair of plastic pipe.

254) Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed.

8.7 Bends and elbows.

255) Each field bend in steel pipe, other than a wrinkle bend made in accordance with section 8.8, must comply with the following:

a) A bend must not impair the serviceability of the pipe.

b) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

c) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:

i) The bend is made with an internal bending mandrel; or

ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.

256) Each circumferential weld of steel pipe 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.

257) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).

258) An operator may not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.

8.8 Wrinkle bends in steel pipe.

259) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.

260) Each wrinkle bend on steel pipe must comply with the following:

a) The bend must not have any sharp kinks;

b) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter;

c) On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than 11⁄2° for each wrinkle; and

d) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

8.9 Protection from hazards.

261) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

262) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

263) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

8.10 Installation of pipe in a ditch.

264) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

265) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:

a) Provides firm support under the pipe; and

b) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

266) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide must be installed so that the top of the pipe is

below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Nearshore pipe (i.e. within 200 ft) and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

267) Promptly after a ditch for an onshore steel transmission line is backfilled (where the construction project involves 1,000 feet or more of continuous backfill length along the pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

268) An operator must notify URCA in accordance with section 2.7 at least 90 calendar days in advance of using other technology to assess integrity of the coating under paragraph 267).

269) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see section 1.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

270) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs 267) through 269) of this section.

8.11 Installation of plastic pipe.

271) Plastic pipe must be installed below ground level except as provided in paragraphs 277), 278), and 279) of this section.

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

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

274) Plastic pipe must have a minimum wall thickness in accordance with section 4.10.

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

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

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

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

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

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

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

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

b) Protected from ultraviolet radiation; and

c) Not allowed to exceed the pipe temperature limits specified in section 4.10.

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

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

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

c) Installations of risers at regulator stations must meet the design requirements of section 5.34.

8.12 Casing.

280) Each casing used on a transmission line or main under a railroad or highway must comply with the following:

281) The casing must be designed to withstand the superimposed loads.

282) Where there is a possibility of water entering the casing, the ends must be sealed.

283) Where the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.

284) Where vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

8.13 Underground clearance.

285) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. Where this clearance cannot be attained, the transmission line must be protected from damage that might result

from the proximity of the other structure.

286) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

287) In addition to meeting the requirements of paragraph 269) or 270) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

288) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in section 5.20, paragraph 142).

8.14 Cover.

289) Except as provided in paragraphs 291), 293) and 294) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal soil	Consolidated rock
Inches (Millimeters)		
Class 1 locations	30 (762)	18 (457)
Class 2, 3, and 4 locations	36 (914)	24 (610)
Drainage ditches of public roads	36 (914)	24 (610)

290) Except as provided in paragraphs 291) and 292) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

291) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover where it is provided with additional protection to withstand anticipated external loads.

292) A main may be installed with less than 24 inches (610 millimeters) of cover where any relevant law of The Bahamas:

a) Establishes a minimum cover of less than 24 inches (610 millimeters);

b) Requires that mains be installed in a common trench with other utility lines; and

c) Provides adequately for prevention of damage to the pipe by external forces.

293) Except as provided in paragraph 291) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

294) All pipe installed offshore under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

a) Except as provided in paragraph 291) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

b) Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

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

295) For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure calculated under section 13.14, a segment must meet the following additional construction requirements. Records must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this construction issue:	The pipeline segment must meet this additional construction requirement:
(a) Quality assurance	(1) The construction of the pipeline segment must be done under a quality assurance plan addressing pipe inspection, hauling and stringing, field bending, welding, non-destructive examination of girth welds, applying and testing field applied coating, lowering of the pipeline into the ditch, padding and backfilling, and hydrostatic testing.
	(2) The quality assurance plan for applying and testing field applied coating to girth welds must be:
	(i) Equivalent to that required under section 4.7(f)(3) for pipe; and
	(ii) Performed by an individual with the knowledge, skills, and ability to assure effective coating application.
(b) Girth welds	(1) All girth welds on a new pipeline segment must be non-destructively examined in accordance with section 6.9 (b) and (c).
(c) Depth of cover	(1) Notwithstanding any lesser depth of cover otherwise allowed in section 8.14, there must be at least 36 inches (914 millimeters) of cover or equivalent means to protect the pipeline from outside force damage.
	(2) In areas where deep tilling or other activities could threaten the pipeline, the top of the pipeline must be installed at least one foot below the deepest expected penetration of the soil.
(d) Initial strength testing	(1) The pipeline segment must not have experienced failures indicative of systemic material defects during strength testing, including initial hydrostatic testing. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic concern. The results of this root cause analysis must be reported to each URCA pipeline safety regional office where the pipe is in service at least 60 calendar days prior to operating at the alternative MAOP. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where URCA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.
(e) Interference currents	(1) For a new pipeline segment, the construction must address the impacts of induced alternating current from parallel electric transmission lines and other known sources of potential interference with corrosion control.

8.16 Installation of plastic pipelines by trenchless excavation.

Plastic pipelines installed by trenchless excavation must comply with the following:

296) Each operator must take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and/or structures at the time of installation.

297) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by section 1.4, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

9 Customer Meters, Service Regulators, and Service Lines

9.1 Scope.

298) This section prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

9.2 Customer meters and regulators: Location.

299) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, where installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried.

300) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

301) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter.

302) Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.

9.3 Customer meters and regulators: Protection from damage.

303) **Protection from vacuum or back pressure.** Where the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.

304) **Service regulator vents and relief vents**. Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must—

a) Be rain and insect resistant;

b) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

c) Be protected from damage caused by submergence in areas where flooding may occur.

305) **Pits and vaults**. Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.

9.4 Customer meters and regulators: Installation.

306) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

307) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this regulation.

308) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

309) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

9.5 Customer meter installations: Operating pressure.

310) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure.

311) Each newly installed meter manufactured must have been tested to a minimum of 10 p.s.i. (69 kPa) gage.

312) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

9.6 Service lines: Installation.

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

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

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

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

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

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

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

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

318) **Installation of service lines under buildings**. Where an underground service line is installed under a building:

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

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

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

319) **Locating underground service lines.** Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with section 8.11, paragraph 275).

9.7 Service lines: Valve requirements.

320) Each service line must have a service-line valve that meets the applicable requirements of sections 3 and 5 of this regulation. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

321) A soft seat service line valve may not be used where its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

322) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

9.8 Service lines: Location of valves.

323) **Relation to regulator or meter**. Each service-line valve must be installed upstream of the regulator or, where there is no regulator, upstream of the meter.

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

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

9.9 Service lines: General requirements for connections to main piping.

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

327) **Compression-type connection to main**. Each compression-type service line to main connection must:

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

b) Where gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system; and

c) Where used on pipelines comprised of plastic, be a Category 1 connection as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area where tested in accordance with the applicable standard.

9.10 Service lines: Connections to cast iron or ductile iron mains.

328) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of section 7.2.

329) Where a threaded tap is being inserted, the requirements of section 5.8, paragraphs 105) and 106) must also be met.

9.11 Service lines: Steel.

330) Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

9.12 Service lines: Cast iron and ductile iron.

331) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

332) Where cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

333) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

9.13 Service lines: Plastic.

334) Each plastic service line outside a building must be installed below ground level, except that—

a) It may be installed in accordance with section 8.11, paragraph 277); and

b) It may terminate above ground level and outside the building, if—

i) The above ground level part of the plastic service line is protected against deterioration and external damage;

ii) The plastic service line is not used to support external loads; and

iii) The riser portion of the service line meets the design requirements of section 5.34.

335) Each plastic service line inside a building must be protected against external damage.

9.14 Installation of plastic service lines by trenchless excavation.

Plastic service lines installed by trenchless excavation must comply with the following:

336) Each operator shall take practicable steps to provide sufficient clearance for installation and

maintenance activities from other underground utilities and structures at the time of installation.

337) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by section 1.4, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

9.15 Service lines: Copper.

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

9.16 New service lines not in use.

339) Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

340) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

341) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

342) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

9.17 Service lines: Excess flow valve performance standards.

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

a) Function properly up to the maximum operating pressure at which the valve is rated;

b) Function properly at all temperatures reasonably expected in the operating environment of the service line;

c) At 10 p.s.i. (69 kPa) gage:

   i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

   ii) Upon closure, reduce gas flow—

      1. For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

      2. For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

d) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

344) An excess flow valve must meet the applicable requirements of sections 3 and 5 of this regulation.

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

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

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

9.18 Excess flow valve installation.

348) **Definitions**. As used in this section:

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

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

"Service Line Serving Single-Family Residence" means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence (SFR).

349) **"Installation Required".** An EFV installation must comply with the performance standards in section 9.17 . Each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated:

a) A single service line to one SFR;

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

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

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

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

350) **"Exceptions To Excess Flow Valve Installation Requirement".** An operator need not install an excess flow valve where one or more of the following conditions are present:

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

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

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

d) An EFV meeting the performance standards in section 9.17 is not commercially available to the operator.

351) **"Customer's Right To Request An EFV"**. Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one of the exceptions in paragraph 350) of this section may request an EFV to be installed on their service lines. Where an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.

352) **"Operator Notification Of Customers Concerning EFV Installation"**. Operators must notify customers of their right to request an EFV in the following manner:

a) Except as specified in paragraphs 350) and e) of this section, each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, Web site postings, and e-billing notices.

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

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

d) The notification must indicate that where a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of paragraph 328) are not present, the operator must install an EFV at a mutually agreeable date.

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

353) **"Operator Evidence Of Customer Notification".** An operator must make a copy of the notice or notices currently in use available during URCA inspections or inspections conducted under a pipeline safety program conducted, certified or approved by URCA under guidelines outlined in U.S.C. 49 60105 or 60106 (incorporated by reference, see section 1.7).

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

by section 2.2.

9.19 Manual service line shut-off valve installation.

355) **Definitions**. As used in this section:

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

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

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

10 Requirements for Corrosion Control

10.1 Scope.

358) This section prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

10.2 How does this section apply to converted pipelines?

359) **Converted pipelines.** Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this regulation in accordance with section 2.5 must meet the requirements of this section specifically applicable to pipelines, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this section specifically applicable to pipelines apply where the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

10.3 General.

360) The corrosion control procedures required by section 13.3, paragraph 484) b), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

10.4 External corrosion control: Buried or submerged pipelines.

361) Except as provided in paragraphs 362), 363), 366), and 367) of this section, each buried or submerged pipeline must be protected against external corrosion, including the following:

a) It must have an external protective coating meeting the requirements of section 10.6.

b) It must have a cathodic protection system designed to protect the pipeline in accordance with this section, installed and placed in operation within 1 year after completion of construction.

362) An operator need not comply with paragraph 361) of this section, where the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. Where the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph 361) b) of this section.

363) An operator need not comply with paragraph 361) of this section, where the operator can demonstrate by tests, investigation, or experience that—

a) For a copper pipeline, a corrosive environment does not exist; or

b) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

364) Notwithstanding the provisions of paragraph 362) or 363) of this section, where a pipeline is externally coated, it must be cathodically protected in accordance with paragraph 361) b) of this section.

365) Aluminum may not be installed in a buried or submerged pipeline where that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

366) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if:

a) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

b) The fitting is designed to prevent leakage caused by localized corrosion pitting.

367) Electrically isolated metal alloy fittings that do not meet the requirements of paragraph 366) must be cathodically protected, and must be maintained in accordance with the operator's integrity management plan.

10.5 External corrosion control: Examination of buried pipeline when exposed.

368) Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion where the pipe is bare, or where the coating is deteriorated. Where external corrosion requiring remedial action under section 10.19 through 10.22 is found, the operator shall 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.

10.6 External corrosion control: Protective coating.

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

a) Be applied on a properly prepared surface;

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

c) Be sufficiently ductile to resist cracking;

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

e) Have properties compatible with any supplemental cathodic protection.

370) Each external protective coating which is an electrically insulating type must also have low

moisture absorption and high electrical resistance.

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

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

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

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

375) An operator must notify URCA in accordance with 2.7 at least 90 calendar days in advance of using other technology to assess integrity of the coating under paragraph 374) of this section.

376) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see 1.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

377) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs 374) through 376) of this section.

10.7 External corrosion control: Cathodic protection.

378) Each cathodic protection system required by this section must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix C of this regulation. Where none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

379) Where amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential—

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

b) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of appendix C of this regulation for amphoteric metals.

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

10.8 External corrosion control: Monitoring and remediation.

381) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of section 10.7. However, where tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

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

a) Each cathodic protection rectifier or impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 21⁄2 months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier.

b) Each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding 15 months.

383) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 21⁄2 months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

384) Each operator must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs 381) through 383) of this section. For onshore gas transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within 1 year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

385) After the initial evaluation required by section 10.4, paragraphs 362) and 363), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this section in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak

repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

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

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

b) To address systemic causes, an operator must conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. An operator must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph 384) of this section. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion.

10.9 External corrosion control: Electrical isolation.

387) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

388) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

389) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, where isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

390) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

391) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

392) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

10.10 External corrosion control: Test stations.

393) Each pipeline under cathodic protection required by this section must have sufficient test stations

or other contact points for electrical measurement to determine the adequacy of cathodic protection.

10.11 External corrosion control: Test leads.

394) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

395) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

396) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

10.12 External corrosion control: Interference currents.

397) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

398) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

399) For onshore gas transmission pipelines, the program required by paragraph 397) of this section must include:

a) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced, such as through co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up-rating, additional lines, new or enlarged power substations, or new pipelines or other structures;

b) Analysis of the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public;

c) Development of a remedial action plan to correct any instances where interference current is greater than or equal to 100 amps per meter squared alternating current (AC), or where it impedes the safe operation of a pipeline, or where it may cause a condition that would adversely impact the environment or the public; and

d) Application for any necessary permits within 6 months of completing the interference survey that identified the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 6 months, after obtaining any necessary permits.

10.13 Internal corrosion control: General.

400) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

401) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. Where internal corrosion is found—

a) The adjacent pipe must be investigated to determine the extent of internal corrosion;

b) Replacement must be made to the extent required by the applicable paragraphs of sections 10.20, 10.21, or 10.22; and

c) Steps must be taken to minimize the internal corrosion.

402) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m.3) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.

10.14 Internal corrosion control: Design and construction of transmission line.

403) **Design and construction**. Except as provided in paragraph 404) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

a) Be configured to reduce the risk that liquids will collect in the line;

b) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

c) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

404) **Exceptions to applicability**. The design and construction requirements of paragraph 403) of this section do not apply to the following:

a) Offshore pipeline; and

b) Pipeline installed or line pipe, valve, fitting or other line component

405) **Change to existing transmission line**. When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

406) **Records.** An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph 403) a), b), or c) of this section is impracticable or unnecessary, an operator may fulfill this requirement through

written procedures supported by as-built drawings or other construction records.

10.15 Internal corrosion control: Monitoring.

407) Where corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 71⁄2 months.

10.16 Internal corrosion control: Onshore transmission monitoring and mitigation.

408) Each operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary. Potentially corrosive constituents include, but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and liquid water, either by itself or in combination. An operator must evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures as necessary.

409) The monitoring and mitigation program described in paragraph 408) of this section must include:

a) The use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents.

b) Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects.

c) An evaluation at least once each calendar year, at intervals not to exceed 15 months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

410) An operator must review its monitoring and mitigation program at least once each calendar year, at intervals not to exceed 15 months, and based on the results of its monitoring and mitigation program, implement adjustments, as necessary.

10.17 Atmospheric corrosion control: General.

411) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph 413) of this section.

412) Coating material must be suitable for the prevention of atmospheric corrosion.

413) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

a) Only be a light surface oxide; or

b) Not affect the safe operation of the pipeline before the next scheduled inspection.

10.18 Atmospheric corrosion control: Monitoring.

414) Each operator must inspect and evaluate each pipeline or portion of the pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

Pipeline type:	Then the frequency of inspection is:
(1) Onshore other than a Service Line	At least once every 3 calendar years, but with intervals not exceeding 39 months.
(2) Onshore Service Line	At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in 405 of this section.
(3) Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

415) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

416) Where atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by 10.17.

417) Where atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months.

10.19 Remedial measures: General.

418) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of 10.6.

419) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this section.

420) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this section.

10.20 Remedial measures: Transmission lines.

421) **General corrosion**. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

422) **Localized corrosion pitting**. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

423) **Calculating remaining strength**. Under paragraphs 421) and 422) of this section, the strength of pipe based on actual remaining wall thickness must be determined and documented in accordance with section 14.9.

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

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

425) **Localized corrosion pitting**. Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

10.22 Remedial measures: Cast iron and ductile iron pipelines.

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

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

10.23 Direct assessment.

428) Each operator that uses direct assessment as defined in section 16.2 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard[1]
External corrosion	16.13[2]
Internal corrosion in pipelines that transport dry gas	16.14
Stress corrosion cracking	16.15

1 For lines not subject to section 16 of this regulation, the terms "covered segment" and

"covered pipeline segment" in sections 16.13, 16.14, and 16.15 refer to the pipeline segment on which direct assessment is performed.

2 In section 16.13, paragraph 754), the provision regarding detection of coating damage applies only to pipelines subject to section 16 of this regulation.

10.24 Corrosion control records.

429) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

430) Each record or map required by paragraph 429) of this section must be retained for as long as the pipeline remains in service.

431) Each operator shall maintain a record of each test, survey, or inspection required by this section in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years with the following exceptions:

a) Operators must retain records related to section 10.8, paragraphs 381) and 385) and 10.9, paragraph 401) for as long as the pipeline remains in service.

b) Operators must retain records of the two most recent atmospheric corrosion inspections for each distribution service line that is being inspected under the interval in 10.18, paragraph 414)(2).

10.25 In-line inspection of pipelines.

432) When conducting in-line inspections of pipelines required by this regulation, an operator must comply with API STD 1163, ANSI/ASNT ILI-PQ, and NACE SP0102, (incorporated by reference, see section 1.7). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.

11 Test Requirements

11.1 Scope.

433) This section prescribes minimum leak-test and strength-test requirements for pipelines.

11.2 General requirements.

434) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

a) It has been tested in accordance with this section and section 13.13 to substantiate the maximum allowable operating pressure; and

b) Each potentially hazardous leak has been located and eliminated.

435) The test medium must be liquid, air, natural gas, or inert gas that is—

a) Compatible with the material of which the pipeline is constructed;

b) Relatively free of sedimentary materials; and

c) Except for natural gas, nonflammable.

436) Except as provided in section 11.3, paragraph 439), where air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

437) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this section, but each non-welded joint must be leak tested at not less than its operating pressure.

438) Where a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, where the manufacturer of the component certifies that:

a) The component was tested to at least the pressure required for the pipeline to which it is being added;

b) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

c) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications (incorporated by reference, see section 1.7), or by unit strength calculations as described in section 5.2.

11.3 Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

439) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, where there is a building intended for human occupancy within 300 feet (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet (91 meters) of such a building, but in no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). However, where the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.

440) In a Class 1 or Class 2 location, each compressor station regulator station, and measuring station, must be tested to at least Class 3 location test requirements.

441) Except as provided in paragraph 442) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.

442) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

11.4 Transmission lines: Spike hydrostatic pressure test.

443) **Spike test requirements**. Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this regulation, the spike hydrostatic pressure test must be conducted in accordance with this section.

a) The test must use water as the test medium.

b) The baseline test pressure must be as specified in the applicable paragraphs of section 13.13, paragraph 533) b) or 13.14, paragraph 539) b), whichever applies.

c) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in section 11.3.

d) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.

444) Other technology or other technical evaluation process. Operators may use other technology or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify URCA 90 calendar days in advance of the

assessment or reassessment requirements of this subchapter. The notification must be made in accordance with section 2.7 and must include the following information.

a) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;

b) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;

c) Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;

d) Assessment techniques and acceptance criteria;

e) Remediation methods for assessment findings;

f) Spike hydrostatic pressure test monitoring and acceptance procedures, where used;

g) Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and

h) Evidence of a review of all procedures and assessments by a qualified technical subject matter expert.

11.5 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

445) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

446) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.

447) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium—

a) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or

b) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.

448) The pressure must be maintained at or above the test pressure for at least 1 hour.

449) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation pressure test must be conducted in accordance with the requirements of this section.

11.6 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

450) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:

451) The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested.

452) Each main that is to be operated at less than 1 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage.

11.7 Test requirements for service lines.

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

454) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (6.9 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage.

455) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i. (276 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with section 11.5.

11.8 Test requirements for plastic pipelines.

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

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

458) The test pressure must be at least 150% of the maximum operating pressure or 50 psi (345 kPa) gauge, whichever is greater. However, the maximum test pressure may not be more than 2.5 times the pressure determined under section 4.10 at a temperature not less than the pipe temperature during the test.

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

11.9 Environmental protection and safety requirements.

460) In conducting tests under this section, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator

shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

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

11.10 Records

462) An operator must make, and retain for the useful life of the pipeline, a record of each test performed under sections 11.3, 11.4, and 11.5. The record must contain at least the following information:

a) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.

b) Test medium used.

c) Test pressure.

d) Test duration.

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

f) Elevation variations, whenever significant for the particular test.

g) Leaks and failures noted and their disposition.

463) Each operator must maintain a record of each test required by sections 11.6, 11.7, and 11.8 for at least 5 years.

12 Uprating

12.1 Scope.

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

12.2 General requirements.

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

a) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

b) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, where it is monitored during the pressure increase and it does not become potentially hazardous.

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

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

468) **Limitation on increase in maximum allowable operating pressure**. Except as provided in section 12.3, paragraph 471), a new maximum allowable operating pressure established under this section may not exceed the maximum that would be allowed under section 13.13 and section 13.15 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, where any variable necessary to determine the design pressure under the design formula (see section 1.5 is unknown, the MAOP may be increased as provided in section 13.13, paragraph 533) a).

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

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

470) Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall:

a) Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this regulation; and

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

471) After complying with paragraph 470) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline to the highest pressure that is permitted under section 13.13 using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

472) After complying with paragraph 470) of this section, an operator that does not qualify under paragraph 471) of this section may increase the previously established maximum allowable operating pressure where at least one of the following requirements is met:

a) The segment of pipeline is successfully tested in accordance with the requirements of this regulation for a new line of the same material in the same location.

b) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location where the line has not previously been tested, and if:

i) It is impractical to test it in accordance with the requirements of this regulation;

ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this regulation.

473) Where a segment of pipeline is uprated in accordance with paragraph 471) or 472) b) of this section, the increase in pressure must be made in increments that are equal to:

a) 10 percent of the pressure before the uprating; or

b) 25 percent of the total pressure increase,

whichever produces the fewer number of increments.

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

474) Unless the requirements of this section have been met, no person may subject:

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

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

475) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

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

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

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

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

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

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

476) After complying with paragraph 475) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i. (69 kPa) gage or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph 475) f) of this section apply, there must be at least two approximately equal incremental increases.

477) Where records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

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

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

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

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

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

13 Operations

13.1 Scope.

479) This section prescribes minimum requirements for the operation of pipeline facilities.

13.2 General provisions.

480) No person may operate a segment of pipeline unless it is operated in accordance with this section.

481) Each operator shall keep records necessary to administer the procedures established under section 13.3.

482) Where the licencee has submitted a statement of Compliance in accordance with the Bahamas Natural Gas Act (s.22(1)(a)(iii)(bb)) with respect to the pipeline facility governed by an operator's plans and procedures, URCA may, after notice and opportunity for hearing, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

13.3 Procedural manual for operations, maintenance, and emergencies.

483) **General**. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

484) **Maintenance and normal operations**. The manual required by paragraph 483) of this section must include procedures for the following, where applicable, to provide safety during maintenance and operations.

a) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this section and section 14.

b) Controlling corrosion in accordance with the operations and maintenance requirements of section 10 of this regulation.

c) Making construction records, maps, and operating history available to appropriate operating personnel.

d) Gathering of data needed for reporting incidents under US CFR Part 191 (incorporated by reference, see section 1.7) of this chapter in a timely and effective manner.

e) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this regulation, plus the build-up allowed for operation of pressure-limiting and control devices.

f) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

g) Starting, operating and shutting down gas compressor units.

h) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.

i) 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.

j) Systematic and routine testing and inspection of pipe-type or bottle-type holders including—

    i) Provision for detecting external corrosion before the strength of the container has been impaired;

    ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, where condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

    iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

k) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under section 13.10, paragraph 516) c) specifically apply to these reports.

l) Implementing the applicable control room management procedures required by section 13.21.

485) **Abnormal operation.** For transmission lines, the manual required by paragraph 483) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

a) Responding to, investigating, and correcting the cause of:

    i) Unintended closure of valves or shutdowns;

    ii) Increase or decrease in pressure or flow rate outside normal operating limits;

    iii) Loss of communications;

    iv) Operation of any safety device; and

    v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

b) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

c) Notifying responsible operator personnel when notice of an abnormal operation is received.

d) 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.

e) The requirements of this paragraph do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.

486) **Safety-related condition reports.** The manual required by paragraph 483) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of US CFR 191.23 (incorporated by reference, see section 1.7).

487) **Surveillance, emergency response, and accident investigation.** The procedures required by sections 13.8, paragraph 509), 13.10, and 13.12 must be included in the manual required by paragraph 483) of this section.

13.4 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

488) **Applicability.** Wherever required by this regulation, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this section.

489) **Documentation of material properties and attributes.** Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at 13.17, paragraph 550) c) or the fracture mechanics requirements at section 14.9 must be maintained for the life of the pipeline.

490) **Verification of material properties and attributes.** Where an operator does not have traceable, verifiable, and complete records required by paragraph 489) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:

a) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.

b) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L (incorporated by reference, see section 1.7).

c) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.

d) Where toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.

e) Verification of material properties and attributes for non-line pipe components must comply with paragraph 493) of this section.

491) **Special requirements for nondestructive Methods**. Procedures developed in accordance with paragraph 490) of this section for verification of material properties and attributes using nondestructive methods must:

a) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;

b) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and

c) Use test equipment that has been properly calibrated for comparable test materials prior to usage.

492) **Sampling multiple segments of pipe**. To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:

a) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. Where the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.

b) For each population defined according to paragraph a) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, in situ evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to section 13.9, until completion of the lesser of the following:

   i) One excavation per mile rounded up to the nearest whole number; or

   ii) 150 excavations where the population is more than 150 miles.

c) Prior tests conducted for a single excavation according to the requirements of paragraph 490) of this section may be counted as one sample under the sampling requirements of this paragraph

492).

d) Where the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify URCA in advance of using an expanded sampling approach in accordance with section 2.7.

e) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph b) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify URCA in advance of using an alternative sampling approach in accordance with section 2.7.

493) **Components**. For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph 490) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5 (incorporated by reference, see section 1.7),

a) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.

b) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:

i) Larger than 2 inches in nominal outside diameter,

ii) Material grades of 42,000 psi (Grade X-42) or greater, or

iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

c) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. Where specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.

494) **Uprating**. The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi in accordance with section 4.4, paragraph 60) b).

13.5 Change in class location: Required study.

495) Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

496) The present class location for the segment involved.

497) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this regulation.

498) The physical condition of the segment to the extent it can be ascertained from available records;

499) The operating and maintenance history of the segment;

500) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

501) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

13.6 Change in class location: Change in valve spacing.

502) Where a class location change on a transmission pipeline results in pipe replacement, of 2 or more miles, in the aggregate, within any 5 contiguous miles within a 24-month period, to meet the maximum allowable operating pressure (MAOP) requirements in sections 13.7, 13.13, or 13.14, then the requirements in sections 5.22, 13.23, and 13.25, as applicable, apply to the new class location, and the operator must install valves, including rupture-mitigation valves (RMV) or alternative equivalent technologies, as necessary, to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with the timing requirement in section 13.7, paragraph 508) for compliance after a class location change.

503) Where a class location change on a gas transmission pipeline results in pipe replacement of less than 2 miles within 5 contiguous miles during a 24-month period, to meet the MAOP requirements in sections 13.7, 13.13, or 13.14, then within 24 months of the class location change, in accordance with section 13.7, paragraph 508), the operator must either:

a) Comply with the valve spacing requirements of section 5.22, paragraph 145) for the replaced pipeline segment; or

b) Install or use existing RMVs or alternative equivalent technologies so that the entirety of the replaced pipeline segments are between at least two RMVs or alternative equivalent technologies. The distance between RMVs and alternative equivalent technologies for the replaced segment shall be installed at a distance taking into account geographical conditions of The Bahamas, but not exceeding 20 miles. The RMVs and alternative equivalent technologies must comply with the applicable requirements of section 13.25.

504) The provisions of paragraph 503) of this section do not apply to pipeline replacements that amount to less than 1,000 feet within any one contiguous mile during any 24-month period.

13.7 Change in class location: Confirmation or revision of maximum allowable operating pressure.

505) Where the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

a) Where the segment involved has been previously tested in place for a period of not less than 8 hours:

i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per section 13.14, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

b) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this regulation for new segments of pipelines in the existing class location.

506) The segment involved must be tested in accordance with the applicable requirements of section 11 of this regulation, and its maximum allowable operating pressure must then be established according to the following criteria:

a) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

b) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

c) For pipeline operating at an alternative maximum allowable operating pressure per 13.14, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

507) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

508) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of sections 12.2 and 12.3. Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under section 13.5 must be completed within 24 months of the change in class location. Pressure reduction under paragraph 506) a) or b) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph 506) c) of this section at a later date

13.8 Continuing surveillance.

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

510) Where a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, where the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with section 13.13, paragraphs 533) and 534).

511) Following an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a flood that exceeds, shoreline, or creek high-water banks in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

a) An operator must assess 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 this paragraph.

b) An operator must commence the inspection required by this paragraph of this section within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection as determined by paragraph a) of this section are available. Where an operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the URCA as soon as practicable.

c) 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 by this paragraph of this section. Such actions might include, but are not limited to:

i) Reducing the operating pressure or shutting down the pipeline;

ii) Modifying, repairing, or replacing any damaged pipeline facilities;

iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;

iv) Performing additional patrols, surveys, tests, or inspections;

v) Implementing emergency response activities with Federal, State, or local personnel; or

vi) Notifying affected communities of the steps that can be taken to ensure public safety.

13.9 Damage prevention program.

512) Except as provided in paragraphs 514) and 515) of this section, 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 purposes 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.

513) The damage prevention program required by paragraph 512) of this section must, at a minimum:

a) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.

b) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph a) of this section of the following as often as needed to make them aware of the damage prevention program.

i) The program's existence and purpose; and

ii) How to learn the location of underground pipelines before excavation activities are begun.

c) Provide a means of receiving and recording notification of planned excavation activities.

d) Where 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.

e) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.

f) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

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

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

a) Pipelines located offshore.

b) Pipelines, other than those located offshore, in Class 1 or 2 locations

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

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

a) The requirement of paragraph 512) of this section that the damage prevention program be written; and

b) The requirements of paragraphs 513), a) and b) of this section.

13.10 Emergency plans.

516) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

a) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

b) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (i.e., 9-1-9 or 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 or 919 emergency call centers in lieu of communicating individually with district-based fire, police, or other public entity. An operator must determine the responsibilities, resources, and emergency contact telephone number(s) for calls of each government organization that may respond to a pipeline emergency, and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies.

c) Prompt and effective response to a notice of each type of emergency, including the following:

i) Gas detected inside or near a building.

ii) Fire located near or directly involving a pipeline facility.

iii) Explosion occurring near or directly involving a pipeline facility.

iv) Natural disaster.

d) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

e) Actions directed toward protecting people first and then property.

f) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released gas to life, property, or the environment.

g) Making safe any actual or potential hazard to life or property.

h) Notifying the appropriate public safety answering point (i.e., 9-1-1 or 9-1-9 emergency call center) where direct access to a 9-1-1 or 9-1-9 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving a notification of potential rupture, as defined in section 1.4, to coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of sections 5.22, 13.23, or 13.25.

i) Safely restoring any service outage.

j) Beginning action under 13.12 where applicable, as soon after the end of the emergency as possible.

k) Actions required to be taken by a controller during an emergency in accordance with the operator's emergency plans and requirements set forth in sections 13.21, 13.23, and 13.25.

l) Each operator must develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in section 1.4, is an actual rupture event or a non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture and identify an actual rupture. For operators installing valves in accordance with sections 5.22, paragraph 149) and 150), or that are subject to the requirements in section 13.23, those procedures must provide for rupture identification as soon as practicable.

517) Each operator shall:

a) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph 516) of this section as necessary for compliance with those procedures.

b) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

c) Review employee activities to determine whether the procedures were effectively followed in each emergency.

518) Each operator must establish and maintain liaison with the appropriate public safety answering point(i.e., 9-1-1 or 9-1-9 emergency call center) where direct access to a 9-1-1 or 9-1-9 emergency call center is available from the location of the pipeline, as well as fire, police, and other public officials, to:

a) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

b) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

c) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

d) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

13.11 Public awareness.

519) Except for an operator of a master meter or petroleum gas system covered under paragraph 528) of this section, each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference, see 1.7).

520) 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.

521) 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.

522) The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

a) Use of a one-call notification system prior to excavation and other damage prevention activities;

b) Possible hazards associated with unintended releases from a gas pipeline facility;

c) Physical indications that such a release may have occurred;

d) Steps that should be taken for public safety in the event of a gas pipeline release; and

e) Procedures for reporting such an event.

523) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

524) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.

525) The program must be conducted in English and in any other languages commonly understood by

a significant number and concentration

526) Upon request, operators must submit their completed programs to URCA

527) The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.

528) Unless the operator transports gas as a primary activity, the operator of a master meter or petroleum gas system is not required to develop a public awareness program as prescribed in paragraphs 519) through 525) of this section. Instead the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. Where the master meter or petroleum gas system is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:

a) A description of the purpose and reliability of the pipeline;

b) An overview of the hazards of the pipeline and prevention measures used;

c) Information about damage prevention;

d) How to recognize and respond to a leak; and

e) How to get additional information.

13.12 Investigation of failures and incidents.

529) **Post-failure and incident procedures.** Each operator must establish and follow procedures for investigating and analyzing failures and incidents as defined in 1.7, including sending the failed pipe, component, or equipment for laboratory testing or examination, where appropriate, for the purpose of determining the causes and contributing factor(s) of the failure or incident and minimizing the possibility of a recurrence.

530) **Post-failure and incident lessons learned.** Each operator must develop, implement, and incorporate lessons learned from a post-failure or incident review into its written procedures, including personnel training and qualification programs, and design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

531) **Analysis of rupture and valve shut-offs.** Where an incident on an onshore gas transmission pipeline involves the closure of a rupture-mitigation valve (RMV), as defined in section 1.7, or the closure of alternative equivalent technology, the operator of the pipeline must also conduct a post-incident analysis of all of the factors that may have impacted the release volume and the consequences of the incident and identify and implement operations and maintenance measures to prevent or minimize the consequences of a future incident. The requirements of this paragraph are not applicable to distribution pipelines. The analysis must include all relevant factors impacting the release volume and consequences, including, but not limited to, the following:

a) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the incident;

b) Appropriateness and effectiveness of procedures and pipeline systems, including supervisory control and data acquisition (SCADA), communications, valve shut-off, and operator personnel;

c) Actual response time from identifying a rupture following a notification of potential rupture, as defined at section 1.7, to initiation of mitigative actions and isolation of the pipeline segment, and the appropriateness and effectiveness of the mitigative actions taken;

d) Location and timeliness of actuation of RMVs or alternative equivalent technologies; and

e) All other factors the operator deems appropriate.

532) **Rupture post-failure and incident summary.** Where a failure or incident on an onshore gas transmission pipeline involves the identification of a rupture following a notification of potential rupture, or the closure of an RMV (as those terms are defined in section 1.4), or the closure of an alternative equivalent technology, the operator of the pipeline must complete a summary of the post-failure or incident review required by paragraph 503) of this section within 90 calendar days of the incident, and while the investigation is pending, conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. The final post-failure or incident summary, and all other reviews and analyses produced under the requirements of this section, must be reviewed, dated, and signed by the operator's appropriate senior executive officer. The final post-failure or incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline. The requirements of this paragraph are not applicable to distribution pipelines .

13.13 Maximum allowable operating pressure: Steel or plastic pipelines.

533) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph iv), 534), or 535) of this section, or the lowest of the following:

a) The design pressure of the weakest element in the segment, determined in accordance with sections 4 and 5 of this regulation. However, for steel pipe in pipelines being converted under 2.5 or uprated under section ‘Uprating of this regulation, where any variable necessary to determine the design pressure under the design formula (section 4.3) is unknown, one of the following pressures is to be used as design pressure:

i) Eighty percent of the first test pressure that produces yield undersection N5 of Appendix N of ASME B31.8 (incorporated by reference, see section 1.7), reduced by the appropriate factor in paragraph b) ii) of this section; or

ii) Where the pipe is 12$_{3/4}$ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

b) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction as follows:

i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

ii) For steel pipe operated at 100 psi (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the table below:

Class location	Factors,[1 2] segment—	
	Installed	Converted under sec. 2.5
1	1.25	1.25
2	1.25	1.25
3	1.5	1.5
4	1.5	1.5

1 For offshore pipeline segments installed, uprated or converted that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

2 For a component with a design pressure established in accordance with 5.9, paragraph 108) or 109), the factor is 1.3.

iii) The highest actual operating pressure to which the segment was subjected during the 5 years in the last five years of operation. This pressure restriction applies unless the segment was tested according to the requirements in paragraph 533) b) of this section after the applicable date in the third column or the segment was uprated according to the requirements in section 12 of this regulation:

iv) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with section 13.23, where applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure.

534) No person may operate a segment unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with section 5.29.

535) The requirements on pressure restrictions in this section do not apply in the following instances:

a) An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the last 5 years of operation. An operator must still comply with section 13.7.

536) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in section 13.14, paragraph 540) may elect to operate the segment at a maximum allowable operating pressure determined under 13.14, paragraph 539).

537) Notwithstanding the requirements in paragraphs 533) through 534) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in 13.17, paragraph 548) must establish and document the maximum allowable operating pressure in accordance with section 13.17.

538) Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs 533) through 537). Operators of pipelines in operation must make and retain records establishing MAOP for the life of the pipeline.

13.14 Alternative maximum allowable operating pressure for certain steel pipelines.

539) **How does an operator calculate the alternative maximum allowable operating pressure?** An operator calculates the alternative maximum allowable operating pressure by using different factors in the same formulas used for calculating maximum allowable operating pressure under 13.13, paragraph 533) as follows:

a) In determining the alternative design pressure under 4.3, use a design factor determined in accordance with section 4.6, paragraph 64), 65) or 66) or, where none of these paragraphs apply, in accordance with the following table:

Class location	Alternative design factor (F)
1	0.80
2	0.67
3	0.56

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

i) The design pressure of the weakest element in the pipeline segment, determined under sections 4 and 5 of this regulation.

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

Class location	Alternative test factor
1	1.25
2	1.50
3	1.50

540) **When may an operator use the alternative maximum allowable operating pressure calculated under paragraph 541) of this section?** An operator may use an alternative maximum allowable operating pressure calculated under paragraph 539) of this section where the following conditions are met:

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

b) The pipeline segment is constructed of steel pipe meeting the additional design requirements in section 4.7;

c) A supervisory control and data acquisition system provides remote monitoring and control of the pipeline segment. The control provided must include monitoring of pressures and flows, monitoring compressor start-ups and shut-downs, and remote closure of valves per paragraph 542) of this section;

d) The pipeline segment meets the additional construction requirements described in section 8.15;

e) The pipeline segment does not contain any mechanical couplings used in place of girth welds;

f) Where a pipeline segment has been previously operated, the segment has not experienced any failure during normal operations indicative of a systemic fault in material as determined by a root cause analysis, including metallurgical examination of the failed pipe. The results of this root cause analysis must be reported to each URCA. where the pipeline is in service at least 60 calendar days prior to operation at the alternative MAOP.

g) At least 95 percent of girth welds on a segment must have been non-destructively examined in accordance with section 6.9, paragraph 211) and 212).

541) **What is an operator electing to use the alternative maximum allowable operating pressure required to do?** Where an operator elects to use the alternative maximum allowable operating pressure calculated under paragraph 539) of this section for a pipeline segment, the operator must do each of the following:

a) For pipelines already in service, notify URCA where the pipeline is in service of the intention to use the alternative pressure at least 180 calendar days before operating at the alternative MAOP. For new pipelines, notify URCA of planned alternative MAOP design and operation at least 60 calendar days prior to the earliest start date of either pipe manufacturing or construction activities.

b) Certify, by signature of a senior executive officer of the company, as follows:

  i) The pipeline segment meets the conditions described in paragraph 540) of this section; and

  ii) The operating and maintenance procedures include the additional operating and maintenance requirements of paragraph 542) of this section; and

  iii) The review and any needed program upgrade of the damage prevention program required by paragraph 542)(4)(v) of this section has been completed.

c) Send a copy of the certification required by paragraph 541) b) of this section to URCA where the pipeline is in service 30 calendar days prior to operating at the alternative MAOP. An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

d) For each pipeline segment, do the following:

  i) Perform a strength test as described in section 11.3 at a test pressure calculated under paragraph 539) of this section or

e) Comply with the additional operation and maintenance requirements described in paragraph 542) of this section.

f) Where the performance of a construction task associated with implementing alternative MAOP can affect the integrity of the pipeline segment, treat that task as a “covered task”, notwithstanding the definition in 15.1 and implement the requirements of section 15 as appropriate.

g) Maintain, for the useful life of the pipeline, records demonstrating compliance with paragraphs 540), 541) f), and 542) of this section.

h) A Class 1 and Class 2 location can be upgraded one class due to class changes per 13.7, paragraph 505). All class location changes from Class 1 to Class 2 and from Class 2 to Class 3 must have all anomalies evaluated and remediated per: The “original pipeline class grade” 13.14, paragraph 542)(11) anomaly repair requirements; and all anomalies with a wall loss equal to or greater than 40 percent must be excavated and remediated. Pipelines in Class 4 may not operate at an alternative MAOP.

542) **What additional operation and maintenance requirements apply to operation at the alternative maximum allowable operating pressure?** In addition to compliance with other applicable safety standards in this regulation, where an operator establishes a maximum allowable operating pressure for a pipeline segment under paragraph 539) of this section, an operator must comply with the additional operation and maintenance requirements as follows:

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
(1) Identifying and evaluating threats	Develop a threat matrix consistent with section 16.9 to do the following: (i) Identify and compare the increased risk of operating the pipeline at the increased stress level under this section with conventional operation; and (ii) Describe and implement procedures used to mitigate the risk.
(2) Notifying the public	(i) Recalculate the potential impact circle as defined in 16.2 to reflect use of the alternative maximum operating pressure calculated under paragraph 539) of this section and pipeline operating conditions; and (ii) In implementing the public education program required under section 13.11 perform the following: (A) Include persons occupying property within 220 yards of the centerline and within the potential impact circle within the targeted audience; and (B) Include information about the integrity management activities performed under this section within the message provided to the audience.

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
(3) Responding to an emergency in an area defined as a high consequence area in section 16.2	(i) Ensure that the identification of high consequence areas reflects the larger potential impact circle recalculated under paragraph (2)(i) of this table. (ii)Where personnel response time to mainline valves on either side of the high consequence area exceeds one hour (under normal driving conditions and speed limits) from the time the event is identified in the control room, provide remote valve control through a supervisory control and data acquisition (SCADA) system, other leak detection system, or an alternative method of control. (iii) Remote valve control must include the ability to close and monitor the valve position (open or closed), and monitor pressure upstream and downstream. (iv) A line break valve control system using differential pressure, rate of pressure drop or other widely-accepted method is an acceptable alternative to remote valve control.
(4) Protecting the right-of-way	(i) Patrol the right-of-way at intervals not exceeding 45 calendar days, but at least 12 times each calendar year, to inspect for excavation activities, ground movement, wash outs, leakage, or other activities or conditions affecting the safety operation of the pipeline. (ii) Develop and implement a plan to monitor for and mitigate occurrences of unstable soil and ground movement. (iii)Where observed conditions indicate the possible loss of cover, perform a depth of cover study and replace cover as necessary to restore the depth of cover or apply alternative means to provide protection equivalent to the originally-required depth of cover. (iv) Use line-of-sight line markers satisfying the requirements of section 14.5, paragraph 600) except in agricultural areas, large water crossings or swamp, steep terrain, or where prohibited by Department of Environmental Planning and Protection (DEPP) Regulations, permits, other statute or any other relevant regulations.

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
	(v) Review the damage prevention program under section 13.9 in light of national consensus practices, to ensure the program provides adequate protection of the right-of-way. Identify the standards or practices considered in the review, and meet or exceed those standards or practices by incorporating appropriate changes into the program. (vi) Develop and implement a right-of-way management plan to protect the pipeline segment from damage due to excavation activities.
(5) Controlling internal corrosion	(i) Develop and implement a program to monitor for and mitigate the presence of, deleterious gas stream constituents. (ii) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and gas quality monitoring equipment. (iii) Use gas quality monitoring equipment that includes a moisture analyzer, chromatograph, and periodic hydrogen sulfide sampling. (iv) Use cleaning pigs and sample accumulated liquids. Use inhibitors when corrosive gas or liquids are present. (v) Address deleterious gas stream constituents as follows: (A) Limit carbon dioxide to 3 percent by volume; (B) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and (C) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas, where the hydrogen sulfide is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points. (vi) Review the program at least quarterly based on the gas stream experience and implement adjustments to monitor for, and mitigate

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
	the presence of, deleterious gas stream constituents.
(6) Controlling interference that can impact external corrosion	(i) Prior to operating an existing pipeline segment at an alternate maximum allowable operating pressure calculated under this section, or within six months after placing a new pipeline segment in service at an alternate maximum allowable operating pressure calculated under this section, address any interference currents on the pipeline segment. (ii) To address interference currents, perform the following: (A) Conduct an interference survey to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected; (B) Analyze the results of the survey; and (C) Take any remedial action needed within 6 months after completing the survey to protect the pipeline segment from deleterious current.
(7) Confirming external corrosion control through indirect assessment	(i) Within six months after placing the cathodic protection of a new pipeline segment in operation, or within six months after certifying a segment under section 13.14, paragraph 541) a) of an existing pipeline segment under this section, assess the adequacy of the cathodic protection through an indirect method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). (ii) Remediate any construction damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP-0502-2002 (incorporated by reference, see section 1.7). (iii) Within six months after completing the baseline internal inspection required under paragraph (9) of this table, integrate the results of the indirect assessment required under paragraph (7)(i) of this table with the results of the baseline internal inspection and take any needed remedial actions.

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
	(iv) For all pipeline segments in high consequence areas, perform periodic assessments as follows: (A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with periodic assessments under section 16. (B) Locate pipe-to-soil test stations at half-mile intervals within each high consequence area ensuring at least one station is within each high consequence area, where practicable. (C) Integrate the results with those of the baseline and periodic assessments for integrity done under paragraph 9 and 10 and of this table.
(8) Controlling external corrosion through cathodic protection	(i)Where an annual test station reading indicates cathodic protection below the level of protection required in section 10, complete remedial action within six months of the failed reading or notify URCA where the pipeline is in service demonstrating that the integrity of the pipeline is not compromised where the repair takes longer than 6 months. (ii) After remedial action to address a failed reading, confirm restoration of adequate corrosion control by a close interval survey on either side of the affected test station to the next test station unless the reason for the failed reading is determined to be a rectifier connection or power input problem that can be remediated and otherwise verified. (iii)Where the pipeline segment has been in operation, the cathodic protection system on the pipeline segment must have been operational within 12 months of the completion of construction.
(9) Conducting a baseline assessment of integrity	(i) Except as provided in paragraph (9)(iii) of this table, for a new pipeline segment operating at the new alternative maximum allowable operating pressure, perform a baseline internal inspection of the entire pipeline segment as follows:

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
	(A) Assess using a geometry tool after the initial hydrostatic test and backfill and within six months after placing the new pipeline segment in service; and (B) Assess using a high resolution magnetic flux tool within three years after placing the new pipeline segment in service at the alternative maximum allowable operating pressure. (ii) Except as provided in paragraph (9)(iii) of this section, for an existing pipeline segment, perform a baseline internal assessment using a geometry tool and a high resolution magnetic flux tool before, but within two years prior to, raising pressure to the alternative maximum allowable operating pressure as allowed under this section. (iii)Where headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portion of a pipeline segment operating at alternative maximum allowable operating pressure cannot accommodate a geometry tool and a high resolution magnetic flux tool, use direct assessment (per section 16.13 , 16.14 and/or 16.15) or pressure testing (per section 11 of this regulation) to assess that portion.
(10) Conducting periodic assessments of integrity	(i) Determine a frequency for subsequent periodic integrity assessments as where all the alternative maximum allowable operating pressure pipeline segments were covered by section 16 of this regulation and (ii) Conduct periodic internal inspections using a high resolution magnetic flux tool on the frequency determined under paragraph (10)(i) of this section, or (iii) Use direct assessment (per section 16.13, 16.14 and/or 16.15) or pressure testing (per section 11 of this regulation) for periodic assessment of a portion of a segment to the extent permitted for a baseline assessment under paragraph (9)(iii) of this section.
(11) Making repairs	(i) Perform the following when evaluating an anomaly:

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
	(A) Use the most conservative calculation for determining remaining strength or an alternative validated calculation based on pipe diameter, wall thickness, grade, operating pressure, operating stress level, and operating temperature: and (B) Take into account the tolerances of the tools used for the inspection. (ii) Repair a defect immediately where any of the following apply: (A) The defect is a dent discovered during the baseline assessment for integrity under paragraph (9) of this section and the defect meets the criteria for immediate repair in section 8.5, paragraph 250). (B) The defect meets the criteria for immediate repair in 16.17, paragraph 768). (C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph 539) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure. (D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph 539) of this section and the failure pressure is less than or equal to 1.4 times the alternative maximum allowable operating pressure. (iii) Where paragraph (11)(ii) of this section does not require immediate repair, repair a defect within one year where any of the following apply: (A) The defect meets the criteria for repair within one year in section 16.17, paragraph 768). (B) The alternative maximum allowable operating pressure was based on a design factor of 0.80 under paragraph 539) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure. (C) The alternative maximum allowable operating pressure was based

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
	on a design factor of 0.67 under paragraph 539) of this section and the failure pressure is less than 1.50 times the alternative maximum allowable operating pressure. (D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph 539) of this section and the failure pressure is less than or equal to 1.80 times the alternative maximum allowable operating pressure. (iv) Evaluate any defect not required to be repaired under paragraph (11)(ii) or (iii) of this table to determine its growth rate, set the maximum interval for repair or re-inspection, and repair or re-inspect within that interval.

543) **Is there any change in overpressure protection associated with operating at the alternative maximum allowable operating pressure?** Notwithstanding the required capacity of pressure relieving and limiting stations otherwise required by section 5.32, where an operator establishes a maximum allowable operating pressure for a pipeline segment in accordance with paragraph 539) of this section, an operator must:

a) Provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the maximum allowable operating pressure; and

b) Develop and follow a procedure for establishing and maintaining accurate set points for the supervisory control and data acquisition system.

13.15 Maximum allowable operating pressure: High-pressure distribution systems.

544) No person may operate a segment of a high-pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

a) The design pressure of the weakest element in the segment, determined in accordance with sections 4 and 1.4 of this regulation.

b) 60 p.s.i. (414 kPa) gage, for a segment of a distribution system otherwise designed to operate at over 60 p.s.i. (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of section 5.30, paragraph 169).

c) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

d) The pressure limits to which a joint could be subjected without the possibility of its parting.

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

545) No person may operate a segment of pipeline to which paragraph 544) e) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with section 5.29.

13.16 Maximum and minimum allowable operating pressure; Low-pressure distribution systems.

546) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

547) No person may operate a low pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

13.17 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

548) **Applicability.** Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section where either of the following conditions are met:

a) Records necessary to establish the MAOP in accordance with section 13.13, paragraph 533) b), including records required by section 11.9, paragraph 462), are not traceable, verifiable, and complete and the pipeline is located in one of the following locations:

ii) A high consequence area as defined in section 16.2; or

iii) A Class 3 or Class 4 location.

b) The pipeline segment's MAOP was established in accordance with 13.13, paragraph 535), the pipeline segment's MAOP is greater than or equal to 30 percent of the specified minimum yield strength, and the pipeline segment is located in one of the following areas:

i) A high consequence area as defined in section 16.2;

ii) A Class 3 or Class 4 location; or

iii) A moderate consequence area as defined in section 1.4, where the pipeline segment can accommodate inspection by means of instrumented inline inspection tools.

549) **Procedures and completion dates**. Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section. These procedures must

include a process for reconfirming MAOP for any pipelines that meet a condition of section 13.17, paragraph 548), and for performing a spike test or material verification in accordance with section 11.4 and 13.4, where applicable. All actions required by this section must be completed according to the following schedule:

a) Operators must complete all actions required by this section as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of section 13.17, paragraph 548) (e.g., due to a location becoming a high consequence area), whichever is later.

b) Where operational and environmental constraints limit an operator from meeting the deadlines in section 13.17, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with section 2.7. The notification must include an up-to-date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and any needed temporary measures needed to mitigate the impact on safety.

550) **Maximum allowable operating pressure determination.** Operators of a pipeline segment meeting a condition in paragraph 546) of this section must reconfirm its MAOP using one of the following methods:

a) **Method 1: Pressure test.** Perform a pressure test and verify material properties records in accordance with section 13.4 and the following requirements:

i) **Pressure test.** Perform a pressure test in accordance with section 11 of this regulation. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in section 13.13, paragraph 533) b) ii).

ii) **Material properties records.** Determine where the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).

iii) **Material properties verification.** Where any of the records required by the previous paragraph are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with section 13.4. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. Where there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with section 13.4.

b) **Method 2: Pressure Reduction.** Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline in the last 5 years of operation, divided by the greater of 1.25 or the applicable class location factor in section 13.13, paragraph 533) b) ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (i.e., the location-specific operating pressure at each location).

i) Where the pipeline segment has had a class location change in accordance with section 13.7, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:

1. For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the last 5 years of operation, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.

2. For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the last 5 years of operation, divided by 2.00.

ii) Future uprating of the pipeline segment in accordance with section 12 is allowed where the MAOP is established using Method 2.

iii) Where an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify URCA in accordance with section 2.7 no later than 7 calendar days after establishing the reduced MAOP. The notification must include the following details:

1. Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in (ii);

2. The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with section 14.9;

3. Justification that establishing MAOP by another method allowed by this section is impractical;

4. Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance with section 13.4, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and

5. Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.

c) **Method 3: Engineering Critical Assessment (ECA).** Conduct an ECA in accordance with section 13.22.

d) **Method 4: Pipe Replacement.** Replace the pipeline segment in accordance with this regulation.

e) **Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius.** Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:

i) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the last 5 years of operation, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (i.e., the location specific operating pressure at each location);

ii) Conduct patrols in accordance with section 14.3 paragraphs 593) and 595) and conduct instrumented leakage surveys in accordance with section 14.4 at intervals not to exceed those in the following table:

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2	$3\frac{1}{2}$ months, but at least four times each calendar year	$3\frac{1}{2}$ months, but at least four times each calendar year.
(B) Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year.

iii) Under Method 5, future uprating of the pipeline segment in accordance with section 12 is allowed.

f) **Method 6: Alternative Technology**. Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. Where an operator elects to use alternative technology, the operator must notify URCA in advance in accordance with section 2.7. The notification must include descriptions of the following details:

i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated;

ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;

iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;

iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;

v) Where any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph 14.9;

vi) Operational monitoring procedures;

vii) Methodology and criteria used to justify and establish the MAOP; and

viii) Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.

551) **Records**. An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

13.18 Odorization of gas.

552) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

553) A combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph 552) of this section unless:

a) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

b) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;

i) An underground storage field;

ii) A gas processing plant;

iii) A gas dehydration plant; or

iv) An industrial plant using gas in a process where the presence of an odorant:

1. Makes the end product unfit for the purpose for which it is intended;

2. Reduces the activity of a catalyst; or

3. Reduces the percentage completion of a chemical reaction;

c) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

d) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

554) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

a) The odorant may not be deleterious to persons, materials, or pipe.

b) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

555) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

556) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

557) To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by—

a) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

b) Conducting periodic “sniff” tests at the extremities of the system to confirm that the gas contains odorant.

13.19 Tapping pipelines under pressure.

558) Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

13.20 Purging of pipelines.

559) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. Where gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

560) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. Where air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

13.21 Control room management.

561) **General.**

a) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section, except that for each control room where an operator's activities are limited to either or both of:

i) Distribution with less than 250,000 services, or

ii) Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs 564) (regarding fatigue), 569) (regarding compliance validation), and 570) (regarding compliance and deviations) of this section.

b) The procedures required by this section must be integrated, as appropriate, with operating and emergency procedures required by sections 13.3 and 13.10.

562) **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:

a) A controller's authority and responsibility to make decisions and take actions during normal operations;

b) A controller's role when an abnormal operating condition is detected, even where the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

c) A controller's role during an emergency, even where the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others;

d) A method of recording controller shift-changes and any hand-over of responsibility between controllers; and

e) The roles, responsibilities and qualifications of others with the authority to direct or supersede the specific technical actions of a controller.

563) **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:

a) Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference, see 1.7) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;

b) 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;

c) 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;

d) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and

e) Establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

564) **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:

a) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;

b) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

c) Train controllers and supervisors to recognize the effects of fatigue; and

d) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit where necessary for the safe operation of a pipeline facility.

565) **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:

a) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

b) 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;

c) Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed 15 months;

d) Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan;

e) Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

f) Address deficiencies identified through the implementation of paragraphs a) through e) of this section.

566) **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:

a) Establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration;

b) Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and

c) Seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.

567) **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:

a) Review incidents that must be reported pursuant to US CFR 49 part 191 (incorporated by reference, see section 1.7) to determine where control room actions contributed to the event and, where so, correct, where necessary, deficiencies related to:

i) Controller fatigue;

ii) Field equipment;

iii) The operation of any relief device;

iv) Procedures;

v) SCADA system configuration; and

vi) SCADA system performance.

b) Include lessons learned from the operator's experience in the training program required by this section.

568) **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:

a) Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

b) Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;

c) Training controllers on their responsibilities for communication under the operator's emergency response procedures;

d) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions;

e) 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

f) 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.

569) **Compliance validation**. Upon request, operators must submit their procedures to URCAURCA. URCA shall be at liberty to liaise and share the procedures submitted to it with any relevant government or statutory agency including but not limited to the Department of Environmental Planning and Protection and the Ministry of Works.

570) **Compliance and deviations.** An operator must maintain for review during inspection:

a) Records that demonstrate compliance with the requirements of this section; and

b) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of a pipeline facility.

13.22 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines.

571) When an operator conducts an MAOP reconfirmation in accordance with section 13.17, "Method 3" using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this section. The ECA must assess: Threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

572) **ECA Analysis.**

a) The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: Diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, where applicable. Where any material properties required to perform an ECA for any pipeline segment in accordance with this paragraph are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with section 13.23. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by section 10 of this regulation, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by sections 13.12, 14.7, and section 16 of this regulation.

b) The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:

i) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with section 14.9.

ii) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI B31G (incorporated by reference, see section 1.7) or R-STRENG (incorporated by reference, see section 1.7) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth).

iii) When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented.

iv) Where SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using section 13.4.

c) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

d) The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in section 13.13, paragraph 533) b) ii).

573) **Assessment to determine defects remaining in the pipe.** An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with paragraph 572) of this section.

a) An operator may use a previous pressure test that complied with section 11 to determine the defects remaining in the pipe where records for a pressure test meeting the requirements of section 11 of this regulation exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in accordance with section 14.9. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a re-assessment interval in accordance with the methodology in section 14.9.

b) Operators may use an inline inspection program in accordance with paragraph 574) of this section.

c) Operators may use “other technology” where it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. Where an operator elects to use “other technology” in the ECA, it must notify URCA in advance of using the other technology in accordance with section 2.7. The “other technology” notification must have:

i) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and

ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.

574) **In-line inspection**. An inline inspection (ILI) program to determine the defects remaining the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking.

a) Where a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.

b) Where the pipeline has had a reportable incident, as defined in section 2.6, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with this section includes an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.

c) Inline inspection must be performed in accordance with section 10.25.

d) An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.

e) Interpretation and evaluation of assessment results must meet the requirements of section 14.7, 14.10, and 16 of this regulation, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations

f) Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in sections 14.10 and 16.17.

575) **Defect remaining life.** Where any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures,

manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with section 14.9.

576) **Records.** An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

13.23 Transmission lines: Onshore valve shut-off for rupture mitigation.

577) **Applicability.** For new or entirely replaced onshore transmission pipeline segments with diameters of 6 inches or greater that are located in high-consequence areas (HCA) or Class 3 or Class 4 locations, an operator must install or use existing rupture-mitigation valves (RMV), or an alternative equivalent technology, according to the requirements of this section and sections 5.2 and 13.25. RMVs and alternative equivalent technologies must be operational within 14 calendar days of placing the new or replaced pipeline segment into service. An operator may request an extension of this 14-day operation requirement where it can demonstrate to URCA , in accordance with the notification procedures in section 2.7, that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this section apply to all applicable pipe replacement projects, even those that do not otherwise involve the addition or replacement of a valve. This section does not apply to pipe segments in Class 1 or Class 2 locations that have a potential impact radius (PIR), as defined in section 16.2, that is less than or equal to 150 feet.

578) **Maximum spacing between valves.** RMVs, or alternative equivalent technology, must be installed in accordance with the following requirements:

a) **Shut-off segment.** For purposes of this section, a “shut-off segment” means the segment of pipe located between the upstream valve closest to the upstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment and the downstream valve closest to the downstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment so that the entirety of the segment that is within the HCA or the Class 3 or Class 4 location is between at least two RMVs or alternative equivalent technologies. Where any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream valves, the shut-off segment also must extend to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or Class 4 locations or HCA segments may be contained within a single shut-off segment. The operator is not required to select the closest valve to the shut-off segment as the RMV, as that term is defined in section 1.4, or the alternative equivalent technology. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, but it must be able to be closed within 30 minutes following rupture identification, as that term is defined at section 1.4. Such a valve used as an alternative equivalent technology would not require a notification to URCA in accordance with section 2.7.

b) **Shut-off segment valve spacing**. A pipeline subject to paragraph 577) of this section must have RMVs or alternative equivalent technology on the upstream and downstream side of the pipeline segment. The distance between RMVs or alternative equivalent technologies must not exceed:

i) Eight (8) miles for any Class 4 location;

ii) Fifteen (15) miles for any Class 3 location; or

iii) Twenty (20) miles for all other locations.

c) **Laterals.** Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of the laterals contributing gas volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment gas volume based upon maximum flow volume at the operating pressure. For laterals that are 12 inches in diameter or less, a check valve that allows gas to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction may be used as an alternative equivalent technology where it is positioned to stop flow into the shut-off segment. Such check valves that are used as an alternative equivalent technology in accordance with this paragraph are not subject to section 13.25 but they must be inspected, operated, and remediated in accordance with section 14.27 including for closure and leakage to ensure operational reliability. An operator using such a check valve as an alternative equivalent technology must notify URCA in accordance with 2.7 and 5.22 and develop and implement maintenance procedures for such equipment that meet section 14.27.

d) **Crossovers**. An operator may use a manual valve as an alternative equivalent technology in lieu of an RMV for a crossover connection if, during normal operations, the valve is closed to prevent the flow of gas by the use of a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must develop and implement operating procedures and document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of gas. An operator using such a manual valve as an alternative equivalent technology must notify URCA in accordance with section 2.7 and 5.22.

13.24 Notification of potential rupture.

579) As used in this regulation, a “notification of potential rupture” refers to the notification of, or observation by, an operator (e.g., by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline:

a) An unanticipated or unexplained pressure loss outside of the pipeline's normal operating pressures, as defined in the operator's written procedures. The operator must establish in its written procedures that an unanticipated or unplanned pressure loss is outside of the pipeline's normal operating pressures when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less, unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in gas demand, gas receipts, or gas deliveries; or

b) An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting paragraph a) of this section; or

c) Any unanticipated or unexplained rapid release of a large volume of gas, a fire, or an explosion in the immediate vicinity of the pipeline.

580) A notification of potential rupture occurs when an operator first receives notice of or observes an event specified in paragraph 579) of this section.

13.25 Transmission lines: Response to a rupture; capabilities of rupture-mitigation valves (RMVs) or alternative equivalent technologies.

581) **Scope**. The requirements in this section apply to rupture-mitigation valves (RMVs), as defined in section 1.4, or alternative equivalent technologies, installed pursuant to sections 5.22, paragraph 149), 150), and 151) and 13.23.

582) **Rupture identification and valve shut-off time**. An operator must, as soon as practicable but within 30 minutes of rupture identification (see section 13.10, paragraph 516) l)), fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of gas released from a pipeline and mitigate the consequences of a rupture.

583) **Open valves**. An operator may leave an RMV or alternative equivalent technology open for more than 30 minutes, as required by paragraph 582) of this section, where the operator has previously established in its operating procedures and demonstrated within a notice submitted under section 2.7 for URCA review, that closing the RMV or alternative equivalent technology would be detrimental to public safety. The request must have been coordinated with appropriate local emergency responders, and the operator and emergency responders must determine that it is safe to leave the valve open. Operators must have written procedures for determining whether to leave an RMV or alternative equivalent technology open, including plans to communicate with local emergency responders and minimize environmental impacts, which must be submitted as part of its notification to URCA .

584) **Valve monitoring and operation capabilities**. An RMV, as defined in section 1.4, or alternative equivalent technology, must be capable of being monitored or controlled either remotely or by on-site personnel as follows:

a) Operated during normal, abnormal, and emergency operating conditions;

b) Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. For automatic shut-off valves (ASV), an operator does not need to monitor remotely a valve's status where the operator has the capability to monitor pressures or gas flow rate within each pipeline segment located between RMVs or alternative equivalent technologies to identify and locate a rupture. Pipeline segments that use manual valves or other alternative equivalent technologies must have the capability to monitor pressures or gas flow rates on the pipeline to identify and locate a rupture; and

c) Have a back-up power source to maintain SCADA systems or other remote communications for remote-control valve (RCV) or automatic shut-off valve (ASV) operational status, or be monitored and controlled by on-site personnel.

585) **Monitoring of valve shut-off response status.** The position and operational status of an RMV must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means. An operator does not need to monitor remotely an ASV's status where the operator has the capability to monitor pressures or gas flow rate on the pipeline to identify and locate a rupture.

586) **Flow modeling for automatic shut-off valves.** Prior to using an ASV as an RMV, an operator must conduct flow modeling for the shut-off segment and any laterals that feed the shut-off segment, so that the valve will close within 30 minutes or less following rupture identification, consistent with the operator's procedures, and in accordance with section 1.4 and this section. The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions that may be encountered during the year, not exceeding a period of 15 months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or gas receipt tie-ins. Where operating conditions change that could affect the ASV set pressures and the 30-minute valve closure time after notification of potential rupture, as defined at section 1.4, an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with section 14.27. The flow model must include a time/pressure chart for the segment containing the ASV where a rupture occurs. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could render the 30-minute valve closure time unachievable.

587) **Manual valves in non-HCA, Class 1 locations.** For pipeline segments in a Class 1 location that do not meet the definition of a high consequence area (HCA), an operator submitting a notification pursuant to sections 2.7 and 5.22 for use of manual valves as an alternative equivalent technology may also request an exemption from the requirements of paragraph 582) of this section.

588) **Manual operation upon identification of a rupture.** Operators using a manual valve as an alternative equivalent technology as authorized pursuant to sections 2.7, 5.22, and 13.23 and this section must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shutoff in accordance with this section and section 13.23. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to shut off all valves manually, not to exceed the maximum response time allowed under paragraph 582) or 583) of this section.

14 Maintenance

14.1 Scope.

589) This section prescribes minimum requirements for maintenance of pipeline facilities.

14.2 General.

590) No person may operate a segment of pipeline, unless it is maintained in accordance with this section.

591) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

592) Hazardous leaks must be repaired promptly.

14.3 Transmission lines: Patrolling.

593) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

594) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

	Maximum interval between patrols	
Class location of line	**At highway crossings**	**At all other places**
1, 2	7½ months; but at least twice each calendar year	15 months; but at least once each calendar year.
3	4½ months; but at least four times each calendar year	7½ months; but at least twice each calendar year.
4	4½ months; but at least four times each calendar year	4½ months; but at least four times each calendar year.

595) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

14.4 Transmission lines: Leakage surveys.

596) Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with section 13.18 without an odor or odorant, leakage surveys using leak detector equipment must be conducted:

a) In Class 3 locations, at intervals not exceeding 7½ months, but at least twice each calendar year; and

b) In Class 4 locations, at intervals not exceeding 4½ months, but at least four times each calendar year.

14.5 Line markers for mains and transmission lines.

597) **Buried pipelines**. Except as provided in paragraph 598) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:

a) At each crossing of a public road; and

b) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

598) **Exceptions for buried pipelines.** Line markers are not required for the following pipelines:

a) Mains and transmission lines located offshore, or at crossings of or under waterways and other bodies of water.

b) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under section 13.9.

c) Transmission lines in Class 3 or 4 locations until March 20, 1996.

d) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.

599) **Pipelines aboveground.** Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

600) **Marker warning.** The following must be written legibly on a background of sharply contrasting color on each line marker:

a) The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with 1⁄4 inch (6.4 millimeters) stroke.

b) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

14.6 Transmission lines: Record keeping.

Each operator shall maintain the following records for transmission lines for the periods specified:

601) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.

602) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by sections 13 and 14 of this regulation must be retained in accordance with paragraph 603) of this section.

603) A record of each patrol, survey, inspection, and test required by sections 13 and 14 of this

regulation must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

14.7 Transmission lines: Assessments outside of high consequence areas.

604) **Applicability**: This section applies to onshore steel transmission pipeline segments with a maximum allowable operating pressure of greater than or equal to 30% of the specified minimum yield strength and are located in:

a) A Class 3 or Class 4 location; or

b) A moderate consequence area as defined in sections 1.4, where the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (i.e., "smart pig").

c) This section does not apply to a pipeline segment located in a high consequence area as defined in section 16.2.

605) **General** —

a) **Initial assessment.** An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of section 14.7, paragraph 604) (e.g., due to a change in class location or the area becomes a moderate consequence area), whichever is later.

b) **Periodic reassessment.** An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.

c) **MAOP verification.** An integrity assessment conducted in accordance with the requirements of 13.17, paragraph 550) for establishing MAOP may be used as an initial assessment or reassessment under this section.

606) **Assessment method**. The initial assessments and the reassessments required by paragraph 605) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods:

a) **Internal inspection.** Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible, such as corrosion, deformation and mechanical damage (e.g., dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with section 10.25;

b) **Pressure test.** Pressure test conducted in accordance with section 11 of this regulation. The use of section 11 pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;

c) **Spike hydrostatic pressure test.** A spike hydrostatic pressure test conducted in accordance with section 11.4. A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

d) **Direct examination.** Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

e) **Guided Wave Ultrasonic Testing.** Guided Wave Ultrasonic Testing (GWUT) as described in Appendix E;

f) **Direct assessment.** Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only where appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in section 16.12 and with the applicable requirements specified in sections 16.13, 16.14 and 16.15; or

g) **Other technology.** Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify URCA in advance of using the other technology in accordance with section 2.7.

607) **Data analysis.** An operator must analyze and account for the data obtained from an assessment performed under paragraph 606) of this section to determine where a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

608) **Discovery of condition.** Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 calendar days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that 180 calendar days is impracticable.

609) **Remediation.** An operator must comply with the requirements in sections 10.20, 14.8, 14.9, 14.10, and 14.11, where applicable, where a condition that could adversely affect the safe operation of a pipeline is discovered.

610) **Analysis of information**. An operator must analyze and account for all available relevant information about a pipeline in complying with the requirements in paragraphs 604) through 609) of this section.

14.8 Transmission lines: General requirements for repair procedures.

611) **Temporary repairs.** Each operator must take immediate temporary measures to protect the public whenever:

a) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and

b) It is not feasible to make a permanent repair at the time of discovery.

612) **Permanent repairs.** An operator must make permanent repairs on its pipeline system according to the following:

a)

i) Non-integrity management repairs for offshore transmission lines: For offshore transmission lines, an operator must make permanent repairs as soon as feasible.

ii) Non-integrity management repairs for onshore transmission lines: Whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered by an integrity management program under section 16 of this regulation, it must correct the condition as prescribed in section 14.11.

b) Integrity management repairs: When an operator discovers a condition on a pipeline covered under 16, the operator must remediate the condition as prescribed by 16.17, paragraph 768).

613) **Welded patch**. Except as provided in section 14.13, paragraph 636) c), no operator may use a welded patch as a means of repair.

14.9 Analysis of predicted failure pressure and critical strain level.

614) **Applicability.** Whenever required by this regulation, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.

615) **Corrosion metal loss.** When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, see 1.7); R-STRENG (incorporated by reference, see 1.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

a) Where an operator would choose to use a remaining strength calculation method that could provide a less conservative result than the methods listed in paragraph 615) introductory text, the operator must notify URCA in advance in accordance with section 2.7, paragraph 32).

b) The notification provided for by paragraph a) of this section must include a comparison of its predicted failure pressures to R-STRENG or ASME/ANSI B31G, all burst pressure tests used, and any other technical reviews used to qualify the calculation method(s) for varying corrosion profiles.

616) **Dents and other mechanical damage.** To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:

a) Identify and evaluate potential threats to the pipe segment in the vicinity of the anomaly or defect, including ground movement, external loading, fatigue, cracking, and corrosion.

b) Review high-resolution magnetic flux leakage (HR-MFL) high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from previous inline inspections.

c) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.

d) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape.

e) Identify and quantify all previous and present significant loads acting on the dent.

f) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or other technology in accordance with this section. Using Finite Element Analysis to quantify the dent strain, and then estimating and evaluating the damage using the Strain Limit Damage (SLD) and Ductile Failure Damage Indicator (DFDI) at the dent, are appropriate evaluation methods.

g) The analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances.

h) Dents with a depth greater than 10 percent of the pipe outside diameter or with geometric strain levels that exceed the lessor of 10 percent or exceed the critical strain for the pipe material properties must be remediated in accordance with sections section 14.10, 14.11, or 16.17, as applicable.

i) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and assuming a reassessment safety factor of 5 or greater for the assessment interval, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section. Multiple dent or other fatigue models must be used for the evaluation as a part of the engineering critical assessment.

j) Where the dent or mechanical damage is suspected to have cracks, then a crack growth rate assessment is required to ensure adequate life for the dent with crack(s) until remediation or the dent with crack(s) must be evaluated and remediated in accordance with the criteria and timing requirements in sections 14.10 , 14.11, or 16.17, as applicable.

k) An operator using an engineering critical assessment procedure, other technologies, or techniques to comply with paragraph 616) of this section must submit advance notification to with the relevant procedures, in accordance with section 2.7.

617) **Cracks and crack-like defects** —

a) **Crack analysis models.** When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).

b) **Analysis for crack growth and remaining life.** Where the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.

i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph 618) b) of this section must be used.

ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).

iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document where further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

c) **Cracks that survive pressure testing.** For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph 617) a) of this section. Where pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:

i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in section 13.23;

iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or

iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify URCA in accordance with section 2.7.

618) **Data.** In performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows.

a) An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using in situ direct measurements.

b) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. Where documented data required for any analysis is not available, an operator must obtain the undocumented data through section 13.4. Until documented material properties are available, the operator shall use conservative assumptions as follows:

i) **Material toughness.** An operator must use one of the following for material toughness:

1. Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

2. A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in section 13.4;

3. Where the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;

4. Where the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or

5. Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify URCA in

advance in accordance with section 2.7 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.

ii) **Material strength**. An operator must assume one of the following for material strength:

1. Grade A pipe (30,000 psi), or

2. The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.

iii) **Pipe dimensions and other data.** Until pipe wall thickness, diameter, or other data are determined and documented in accordance with section 13.4, the operator must use values upon which the current MAOP is based.

619) **Review**. Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.

620) **Records**. An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:

a) The technical approach used for the analysis;

b) All data used and analyzed;

c) Pipe and weld properties;

d) Procedures used;

e) Evaluation methodology used;

f) Models used;

g) Direct in situ examination data;

h) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;

i) Pressure test data and results;

j) In-the-ditch assessments;

k) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;

l) All finite element analysis results;

m) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;

n) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;

o) Safety factors used for fatigue life and/or predicted failure pressure calculations;

p) Reassessment time interval and safety factors;

q) The date of the review;

r) Confirmation of the results by qualified technical subject matter experts; and

s) Approval by responsible operator management personnel.

621) **Reassessments**. Where an operator uses an engineering critical assessment method in accordance with paragraphs 616) and 617) of this section to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows:

a) Where the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of 7 years in accordance with section 16.20, paragraph 781), unless the safety factor is expected to go below what is specified in paragraph 616) or 617) of this section.

b) Where the anomaly is outside of an HCA, the operator must perform a reassessment of the anomaly within a maximum of 10 years in accordance with section 14.7, paragraph 605), unless the anomaly safety factor is expected to go below what is specified in paragraph 616) or 617) of this section.

14.10 Transmission lines: Permanent field repair of imperfections and damages.

622) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

a) Removed by cutting out and replacing a cylindrical piece of pipe; or

b) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

623) Operating pressure must be at a safe level during repair operations.

14.11 Transmission lines: Repair criteria for onshore transmission pipelines.

624) **Applicability**. This section applies to onshore transmission pipelines not subject to the repair criteria in section 16 of this regulation, and which do not operate under an alternative MAOP in accordance with sections 4.7, 8.15, and 13.14. Pipeline segments that are located in high consequence areas, as defined in section 16.2, must comply with the applicable actions specified by the integrity management requirements in section 16. Pipeline segments operating under an alternative MAOP in accordance with sections 4.7, 17.15, and 13.14 must comply with section 13.14, paragraph 542)(11).

625) **General**. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A

pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with section 14.9 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. Where documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through section 13.4. Until documented material properties are available, the operator must use the conservative assumptions in either section 14.9, paragraph 618) b) or, where appropriate following a pressure test, in section 14.9, paragraph 617) c).

626) **Schedule for evaluation and remediation.** An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless paragraph 594 of this section provides a special requirement for remediating certain conditions, an operator must calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see section 1.7), section 7, Figure 4.Where an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that meets any of the repair criteria in paragraph 627) of this section in an onshore steel transmission pipeline must be—

a) Removed by cutting out and replacing a cylindrical piece of pipe that will permanently restore the pipeline's MAOP based on the use of section 4.3 and the design factors for the class location in which it is located; or

b) Repaired by a method, shown by technically proven engineering tests and analyses, that will permanently restore the pipeline's MAOP based upon the determined predicted failure pressure times the design factor for the class location in which it is located.

627) **Remediation of certain conditions.** For onshore transmission pipelines not located in high consequence areas, an operator must remediate a listed condition according to the following criteria:

a) **Immediate repair conditions.** An operator's evaluation and remediation schedule for immediate repair conditions must follow section 7 of ASME/ANSI B31.8S (incorporated by reference, see section 1.7). An operator must repair the following conditions immediately upon discovery:

i) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with section 14.9 , paragraph 615), of less than or equal to 1.1 times the MAOP.

ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with section 14.9, paragraph 616) demonstrates critical strain levels are not exceeded.

iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

iv) Metal loss preferentially affecting a detected longitudinal seam, where that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with section 14.9, paragraph 617) is less than 1.25 times the

MAOP.

v) A crack or crack-like anomaly meeting any of the following criteria:

1. Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

2. Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

3. The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with section 14.9, paragraph 617), that is less than 1.25 times the MAOP.

vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

b) **Two-year conditions.** An operator must repair the following conditions within 2 years of discovery:

i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with section 14.9, paragraph 616) demonstrates critical strain levels are not exceeded.

ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis performed in accordance with section 14.9, paragraph 616) demonstrates critical strain levels are not exceeded.

iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1⁄3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with section 14.9, paragraph 616) demonstrates critical strain levels are not exceeded.

iv) For metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with section 14.9, paragraph 615) at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, see section 1.7), section 7, Figure 4, as specified in paragraph 626) of this section.

v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, and that has a predicted failure pressure, determined in accordance with section 14.9, paragraph 615), less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with section 13.7, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

vi) Metal loss preferentially affecting a detected longitudinal seam, where that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with section 14.9, paragraph 617) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with section 13.7, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with section 14.9, paragraph 617), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with section 13.7, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

c) **Monitored conditions.** An operator must record and monitor the following conditions during subsequent risk assessments and integrity assessments for any change that may require remediation.

i) A dent that is located between the 4 o'clock and 8 o'clock positions (bottom 1⁄3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis, performed in accordance with section 14.9, paragraph 616), demonstrates critical strain levels are not exceeded.

ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with section 14.9, paragraph 616) determines that critical strain levels are not exceeded.

iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with section 14.9, paragraph 616), demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties.

iv) A dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with section 14.9, paragraph 616) demonstrates critical strain levels are not exceeded.

v) Metal loss preferentially affecting a detected longitudinal seam, where that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with section 14.9, paragraph 617), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with section 13.7, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with section 14.9, paragraph 617), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with section 13.7, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

628) **Temporary pressure reduction.**

a) Immediately upon discovery and until an operator remediates the condition specified in paragraph 627) a) of this section, or upon a determination by an operator that it is unable to respond within the time limits for the conditions specified in paragraph 627) b) of this section, the operator must reduce the operating pressure of the affected pipeline to any one of the following based on safety considerations for the public and operating personnel:

i) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

ii) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

iii) A level not exceeding the predicted failure pressure divided by 1.1.

b) An operator must notify URCA in accordance with section 2.7 where it cannot meet the schedule for evaluation and remediation required under paragraph 626) or 627) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to URCA does not alleviate an operator from the evaluation, remediation, or pressure reduction requirements in this section.

c) When a pressure reduction, in accordance with paragraph 628) of this section, exceeds 365 calendar days, an operator must notify URCA in accordance with section 2.7 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

d) An operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure and the implementation of the actual reduced operating pressure for a period of 5 years after the pipeline has been repaired.

629) **Other conditions**. Unless another timeframe is specified in paragraph 627) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules, and methods defined in the operator's operating and maintenance procedures.

630) **In situ direct examination of crack defects.** Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. "In situ" examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld

surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

631) **Determining predicted failure pressures and critical strain levels.** An operator must perform all determinations of predicted failure pressures and critical strain levels required by this section in accordance with section 14.9.

14.12 Transmission lines: Permanent field repair of welds.

Each weld that is unacceptable under section 6.8, paragraph 209) must be repaired as follows:

632) Where it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of section 16.10.

633) A weld may be repaired in accordance with section 16.10 while the segment of transmission line is in service if:

a) The weld is not leaking;

b) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and

c) Grinding of the defective area can be limited so that at least 1⁄8-inch (3.2 millimeters) thickness in the pipe weld remains.

634) A defective weld which cannot be repaired in accordance with paragraph 632) or 633) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

14.13 Transmission lines: Permanent field repair of leaks.

Each permanent field repair of a leak on a transmission line must be made by:

635) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or

636) Repairing the leak by one of the following methods:

a) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS.

b) Where the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.

c) Where the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (267 Mpa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.

d) Where the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design.

e) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

14.14 Transmission lines: Testing of repairs.

637) Testing of replacement pipe. Where a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

638) Testing of repairs made by welding. Each repair made by welding in accordance with sections 14.10, 14.12, and 14.13 must be examined in accordance with section 6.8.

14.15 Distribution systems: Leak repair.

639) Mechanical leak repair clamps may not be used as a permanent repair method for plastic pipe.

14.16 Distribution systems: Patrolling.

640) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.

641) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

a) In business districts, at intervals not exceeding 4½ months, but at least four times each calendar year; and

b) Outside business districts, at intervals not exceeding 7½ months, but at least twice each calendar year.

14.17 Distribution systems: Leakage surveys.

642) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section.

643) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

a) A leakage survey with leak detector equipment must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year.

b) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months. However, for cathodically unprotected distribution lines subject to section 10.8, paragraph 385) on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least once every 3 calendar years at intervals not exceeding 39 months.

14.18 Test requirements for reinstating service lines.

644) Except as provided in paragraph 645) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

645) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, where provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

14.19 Abandonment or deactivation of facilities.

646) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.

647) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

648) Except for service lines, each inactive pipeline that is not being maintained under this regulation must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

649) Whenever service to a customer is discontinued, one of the following must be complied with:

a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

650) Where air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

651) Each abandoned vault must be filled with a suitable compacted material.

652) 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.

14.20 Compressor stations: Inspection and testing of relief devices.

653) Except for rupture discs, each pressure relieving device in a compressor station must be inspected

and tested in accordance with section 14.23 and 14.26, and must be operated periodically to determine that it opens at the correct set pressure.

654) Any defective or inadequate equipment found must be promptly repaired or replaced.

655) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

14.21 Compressor stations: Storage of combustible materials.

656) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

657) Aboveground oil or gasoline storage tanks must be protected in accordance with NFPA-30 (incorporated by reference, see section 1.7), and any rules made by the Minister in accordance with the Bahamas Inflammable Liquids Act 2001.

14.22 Compressor stations: Gas detection.

658) Each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is—

a) Constructed so that at least 50 percent of its upright side area is permanently open; or

b) Located in an unattended field compressor station of 1,000 horsepower (746 kW) or less.

659) Except when shutdown of the system is necessary for maintenance under paragraph 660) of this section, each gas detection and alarm system required by this section must—

a) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and

b) Where that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.

660) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

14.23 Pressure limiting and regulating stations: Inspection and testing.

661) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

a) In good mechanical condition;

b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

c) Except as provided in paragraph 662) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of section 5.32, paragraph 180); and

d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

662) For steel pipelines whose MAOP is determined under section 13.13, paragraph 535), where the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

Where the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS	MAOP plus 4 percent.
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

14.24 Pressure regulating, limiting, and overpressure protection—Individual service lines directly connected to transmission pipelines.

663) This section applies, except as provided in paragraph 665) of this section, to any service line directly connected to a transmission pipeline that is not operated as part of a distribution system.

664) Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every 3 calendar years, not exceeding 39 months, to determine that it is:

a) In good mechanical condition;

b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

c) Set to control or relieve at the correct pressure consistent with the pressure limits of section 5.30; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and

d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

665) This section does not apply to equipment installed on:

a) A service line that only serves engines that power irrigation pumps;

b) A service line included in a distribution integrity management plan meeting the requirements of section 17 of this regulation; or

14.25 Pressure limiting and regulating stations: Telemetering or recording gauges.

666) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district.

667) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

668) Where there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

14.26 Pressure limiting and regulating stations: Capacity of relief devices.

669) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in section 14.23, paragraph 662), the capacity must be consistent with the pressure limits of section 5.32, paragraph 180). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

670) Where review and calculations are used to determine where a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made where the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

671) Where a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph 669) of this section.

14.27 Valve maintenance: Transmission lines.

672) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

673) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

674) For each remote-control valve (RCV) installed in accordance with section 5.22 or section 13.23, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with section 13.21, paragraph 563) and 565).

675) For each alternative equivalent technology installed on an onshore pipeline under section 5.22, paragraphs 149) or 150), or section 13.23 that is manually or locally operated (i.e., not a rupture-mitigation valve (RMV), as that term is defined in section 1.4):

a) Operators must achieve a valve closure time of 30 minutes or less, pursuant to section 13.25, paragraph 582), through an initial drill and through periodic validation as required in paragraph b) of this section. An operator must review and document the results of each phase of the drill response to validate the total response time, including confirming the rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification.

b) Within each pipeline system and within each operating or maintenance field work unit, operators must randomly select a valve serving as an alternative equivalent technology in lieu of an RMV for an annual 30-minute-total response time validation drill that simulates worst-case conditions for that location to ensure compliance with section 13.25. Operators are not required to close the valve fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance with drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar year, with intervals not to exceed 15 months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph.

c) Where the 30-minute-maximum response time cannot be achieved during the drill, the operator must revise response efforts to achieve compliance with section 13.25 as soon as practicable but no later than 12 months after the drill. Alternative valve shut-off measures must be in place in accordance with paragraph 676) of this section within 7 calendar days of a failed drill.

d) Based on the results of response-time drills, the operator must include lessons learned in:

i) Training and qualifications programs;

ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and

iii) Any other areas identified by the operator as needing improvement.

e) The requirements of this paragraph do not apply to manual valves who, pursuant to section 13.25 , paragraph 587), have been exempted from the requirements of section 13.25, paragraph 582).

f) Each operator must develop and implement remedial measures to correct any valve installed on an onshore pipeline under section 5.22, paragraph 149) or 150) or 13.23 that is indicated to be inoperable or unable to maintain effective shut-off as follows:

i) Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain effective shut-off. An operator must request an extension from URCA in accordance with section 2.7 where repair or replacement of a valve within 12 months would be economically, technically, or operationally infeasible; and

ii) Designate an alternative valve acting as an RMV within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Such valves are not required to comply with the valve spacing requirements of this regulation.

676) An operator using an ASV as an RMV, in accordance with sections 1.4, 5.22, 13.23, and 13.25, must document and confirm the ASV shut-in pressures, in accordance with 13.25 paragraph 586), on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required, on a calendar year basis not to exceed 15 months.

14.28 Valve maintenance: Distribution systems.

677) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.

678) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

14.29 Vault maintenance.

679) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.

680) Where gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

681) The ventilating equipment must also be inspected to determine that it is functioning properly.

682) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

14.30 Launcher and receiver safety.

683) Any launcher or receiver must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (e.g. inspection tools, scrapers, or spheres), where pressure has not been relieved.

14.31 Prevention of accidental ignition.

684) Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

685) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

686) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

687) Post warning signs, where appropriate.

14.32 Caulked bell and spigot joints.

688) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psi (172kPa) gage must be sealed with:

a) A mechanical leak clamp; or

b) A material or device which:

i) Does not reduce the flexibility of the joint;

ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of section 3.2, paragraph 34) and 35) and section 5.2.

689) Each cast iron caulked bell and spigot joint that is subject to pressures of 25 psi (172kPa) gage or less and is exposed for any reason must be sealed by a means other than caulking.

14.33 Protecting cast-iron pipelines.

690) When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

691) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

a) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

b) Impact forces by vehicles;

c) Earth movement;

d) Apparent future excavations near the pipeline; or

e) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

692) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of sections 8.9, paragraph 261), 8.10, and 9.6, paragraphs 314)-316).

14.34 Joining plastic pipe by heat fusion; equipment maintenance and calibration.

693) Each operator must maintain equipment used in joining plastic pipe in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.

15 Qualification of Pipeline Personnel

15.1 Scope.

694) This section prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

695) For the purpose of this section, a covered task is an activity, identified by the operator, that:

a) Is performed on a pipeline facility;

b) Is an operations or maintenance task;

c) Is performed as a requirement of this regulation; and

d) Affects the operation or integrity of the pipeline.

15.2 Definitions.

"Abnormal Operating Condition" means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

a) Indicate a condition exceeding design limits; or

b) Result in a hazard(s) to persons, property, or the environment.

"Evaluation" means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

a) Written examination;

b) Oral examination;

c) Work performance history review;

d) Observation during:

   i) Performance on the job,

   ii) On the job training, or

   iii) Simulations;

e) Other forms of assessment.

"Qualified" means that an individual has been evaluated and can:

a) Perform assigned covered tasks; and

b) Recognize and react to abnormal operating conditions.

15.3 Qualification program.

696) Each operator shall have and follow a written qualification program. The program shall include provisions to:

a) Identify covered tasks;

b) Ensure through evaluation that individuals performing covered tasks are qualified;

c) Allow individuals that are not qualified pursuant to this section to perform a covered task where directed and observed by an individual that is qualified;

d) Evaluate an individual where the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in US CFR Part 191 (incorporated by reference, see section 1.7) ;

e) Evaluate an individual where the operator has reason to believe that the individual is no longer qualified to perform a covered task;

f) Communicate changes that affect covered tasks to individuals performing those covered tasks;

g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed;

h) 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

i) Notify URCA if an operator significantly modifies the program after URCA has verified that it complies with this section. Notifications to URCA must be submitted in accordance with section 2.7.

15.4 Recordkeeping.

697) Each operator shall maintain records that demonstrate compliance with this section.

698) Qualification records shall include:

a) Identification of qualified individual(s);

b) Identification of the covered tasks the individual is qualified to perform;

c) Date(s) of current qualification; and

d) Qualification method(s).

699) 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.

15.5 General.

700) Operators must have a written qualification program. The program must be available for review by URCA.

16 Gas Transmission Pipeline Integrity Management

16.1 What do the regulations in this section cover?

701) This section prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this regulation. For gas transmission pipelines constructed of plastic, only the requirements in sections 16.9, 16.11, 16.18 and 16.19 apply.

16.2 Definitions

The following definitions apply to this section:

"Assessment" is the use of testing techniques as allowed in this section to ascertain the condition of a covered pipeline segment.

"**Confirmatory Direct Assessment**" is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

"Covered Segment Or Covered Pipeline Segment" means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in section 1.4.

"Direct Assessment" is an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered 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.

"High Consequence Area" means an area established by one of the methods described in paragraphs a) or b) as follows:

a) An area defined as—

i) A Class 3 location under section 1.5; or

ii) A Class 4 location under section 1.5; or

iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

b) The area within a potential impact circle containing—

i) 20 or more buildings intended for human occupancy, unless the exception in paragraph ii) applies; or

ii) An identified site.

e) Where a potential impact circle is calculated under either method (i) or (ii) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See figure E.I.A. in appendix D.)

f) Where in identifying a high consequence area under paragraph (i)(c) of this definition or paragraph (ii)(a) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy with a distance of 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006.Where an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to 20 × (660 feet) [or 200 meters]/potential impact radius in feet [or meters]2).

"**Identified site**" means each of the following areas:

a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 (fifty) calendar days in any twelve (12)-month period. (The calendar days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

b) A building that is occupied by twenty (20) or more persons on at least five (5) calendar days a week for ten (10) weeks in any twelve (12)-month period. (The calendar days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or

c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

"**Potential Impact Circle**" is a circle of radius equal to the potential impact radius (PIR).

"**Potential Impact Radius (PIR**)" means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d2)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S (incorporated by reference, see 1.7) to calculate the impact radius formula.

"**Remediation**" is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

16.3 How does an operator identify a high consequence area?

702) **General**. To determine which segments of an operator's transmission pipeline system are covered by this section, an operator must identify the high consequence areas. An operator must use method (i) or (ii) from the definition in section 16.2 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See appendix D.I. for guidance on identifying high consequence areas.)

703)

a) **Identified sites**. An operator must identify an identified site, for purposes of this section, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials from the Fire Department, NEMA, the DEPP or other Government Department authorized to request such information.

b) Where a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.

i) Visible marking (e.g., a sign); or

ii) The site is licensed or registered by a statutory body or regulatory or government agency; or

iii) The site is on a list (including a list on an internet web site) or map maintained by or available from statutory body or regulatory or government agency.

704) **Newly identified areas.** When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in section 16.2, the operator must complete the evaluation using method (1) or (2). Where the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

16.4 What must an operator do to implement this section?

705) **General**. An operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in section 16.6 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive

program. An operator must make continual improvements to the program.

706) **Implementation Standards**. In carrying out this section, an operator must follow the requirements of this section and of ASME/ANSI B31.8S (incorporated by reference, see section 1.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this section and ASME/ANSI B31.8S, the requirements in this section control.

16.5 How can an operator change its integrity management program?

707) **General**. An operator must document any change to its program and the reasons for the change before implementing the change.

708) **Notification**. An operator must notify URCA, in accordance with section 2.7, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must provide notification within 30 calendar days after adopting this type of change into its program.

16.6 What are the elements of an integrity management program?

709) An operator's initial integrity management program begins with a framework (see section 16.4) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, see section 1.7) for more detailed information on the listed element.)

710) An identification of all high consequence areas, in accordance with section 16.3.

711) A baseline assessment plan meeting the requirements of 16.10 and 16.11.

712) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (16.9) and to evaluate the merits of additional preventive and mitigative measures (16.18) for each covered segment.

713) A direct assessment plan, where applicable, meeting the requirements of section 16.12, and depending on the threat assessed, of sections 16.13, 16.14, or 16.15.

714) Provisions meeting the requirements of section 16.17 for remediating conditions found during an integrity assessment.

715) A process for continual evaluation and assessment meeting the requirements of 16.19.

716) Where applicable, a plan for confirmatory direct assessment meeting the requirements of section 16.16.

717) Provisions meeting the requirements of section 16.18 for adding preventive and mitigative

measures to protect the high consequence area.

718) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of section 16.23.

719) Record keeping provisions meeting the requirements of section 16.24.

720) A management of change process as required by section 2.4, paragraph 23).

721) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

722) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—

a) URCA; and

b) DEEP and Ministry of Public Works

723) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—

a) URCA; and

b) DEPP and Ministry of Public Works

724) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

725) A process for identification and assessment of newly-identified high consequence areas. (See section 16.3 and section 16.11).

16.7 When may an operator deviate its program from certain requirements of this section?

726) **General**. ASME/ANSI B31.8S (incorporated by reference, see section 1.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph 727) of this section may deviate from certain requirements in this section, as provided in paragraph 728) of this section.

727) **Exceptional performance**. An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions.

a) To deviate from any of the requirements set forth in paragraph 728) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements—

i) A comprehensive process for risk analysis;

ii) All risk factor data used to support the program;

iii) A comprehensive data integration process;

iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this section;

v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;

vii) Semi-annual performance measures beyond those required in section 16.23 that are part of the operator's performance plan. (See section 16.6, paragraph 718)) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with section 16.25; and

viii) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

b) In addition to the requirements for the performance-based plan, an operator must—

i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.

ii) Remediate all anomalies identified in the more recent assessment according to the requirements in section 16.17, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

728) **Deviation**. Once an operator has demonstrated that it has satisfied the requirements of paragraph 727) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this section only in the following instances.

a) The time frame for reassessment as provided in section 16.20 except that reassessment by some method allowed under this section (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years;

b) The time frame for remediation as provided in section 16.17 where the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

16.8 What knowledge and training must personnel have to carry out an integrity management program?

729) **Supervisory personnel.** The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a

thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

730) Persons who carry out assessments and evaluate assessment results. The integrity management program must provide criteria for the qualification of any person—

a) Who conducts an integrity assessment allowed under this section; or

b) Who reviews and analyzes the results from an integrity assessment and evaluation; or

c) Who makes decisions on actions to be taken based on these assessments.

731) **Persons responsible for preventive and mitigative measures.** The integrity management program must provide criteria for the qualification of any person—

a) Who implements preventive and mitigative measures to carry out this section, including the marking and locating of buried structures; or

b) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

16.9 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

732) **Threat identification.** An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see section 1.7), section 2, which are grouped under the following four threat categories:

a) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

b) Stable threats, such as manufacturing, welding, fabrication, or construction defects;

c) Time independent threats, such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage, to include consideration of seismicity, geology, and soil stability of the area; and

d) Human error, such as operational or maintenance mishaps, or design and construction mistakes.

733) **Data gathering and integration.** To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4.

Operators must begin to integrate all pertinent data elements specified in this section as soon as practicable. An operator must gather and evaluate the set of data listed in paragraph a) of this section. The evaluation must analyze both the covered segment and similar non-covered segments, and it must:

a) Integrate pertinent information about pipeline attributes to ensure safe operation and pipeline integrity, including information derived from operations and maintenance activities required under this regulation, and other relevant information, including, but not limited to:

   i) Pipe diameter, wall thickness, seam type, and joint factor;

   ii) Manufacturer and manufacturing date, including manufacturing data and records;

   iii) Material properties including, but not limited to, grade, specified minimum yield strength (SMYS), and ultimate tensile strength;

   iv) Equipment properties;

   v) Year of installation;

   vi) Bending method;

   vii) Joining method, including process and inspection results;

   viii) Depth of cover;

   ix) Crossings, casings (including where shorted), and locations of foreign line crossings and nearby high voltage power lines;

   x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;

   xi) Pipe coating methods (both manufactured and field applied), including the method or process used to apply girth weld coating, inspection reports, and coating repairs;

   xii) Soil, backfill;

   xiii) Construction inspection reports, including but not limited to:

      1. Post backfill coating surveys; and

      2. Coating inspection ("jeeping" or "holiday inspection") reports;

   xiv) Cathodic protection installed, including, but not limited to, type and location;

   xv) Coating type;

   xvi) Gas quality;

   xvii) Flow rate;

   xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);

xix) Class location;

xx) Leak and failure history, including any in-service ruptures or leaks from incident reports, abnormal operations, safety-related conditions (both reported and unreported) and failure investigations required by section 13.12, and their identified causes and consequences;

xxi) Coating condition;

xxii) Cathodic protection (CP) system performance;

xxiii) Pipe wall temperature;

xxiv) Pipe operational and maintenance inspection reports, including, but not limited to:

1. Data gathered through integrity assessments required under this regulation, including, but not limited to, in-line inspections, pressure tests, direct assessments, guided wave ultrasonic testing, or other methods;

2. Close interval survey (CIS) and electrical survey results;

3. CP rectifier readings;

4. CP test point survey readings and locations;

5. Alternating current, direct current, and foreign structure interference surveys;

6. Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including, but not limited to, direct current voltage gradient or alternating current voltage gradient inspections;

7. Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see section 10.5), including the results of any non-destructive examinations of the pipe, seam, or girth weld (i.e. bell hole inspections);

8. Stress corrosion cracking excavations and findings;

9. Selective seam weld corrosion excavations and findings;

10. Any indication of seam cracking; and

11. Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

xxv) External and internal corrosion monitoring;

xxvi) Operating pressure history and pressure fluctuations, including an analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

xxviii) Encroachments;

xxix) Repairs;

xxx)Vandalism;

xxxi) External forces;

xxxii) Audits and reviews;

xxxiii) Industry experience for incident, leak, and failure history;

xxxiv) Aerial photography; and

xxxv) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area.

b) Use validated information and data as inputs, to the maximum extent practicable. Where input is obtained from subject matter experts (SME), an operator must employ adequate control measures to ensure consistency and accuracy of information. Control measures may include training of SMEs or the use of outside technical experts (independent expert reviews) to assess the quality of processes and the judgment of SMEs. An operator must document the names and qualifications of the individuals who approve SME inputs used in the current risk assessment.

c) Identify and analyze spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings or evidence of pipeline damage where overhead imaging shows evidence of encroachment).

d) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

734) **Risk assessment.** An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and that analyzes the identified threats and potential consequences of an incident for each covered segment. An operator must ensure the validity of the methods used to conduct the risk assessment considering the incident, leak, and failure history of the pipeline segments and other historical information. Such a validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the likelihood of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed for each covered segment in accordance with section 16.18 and periodically evaluate the integrity of each covered pipeline segment in accordance with 16.19. The risk assessment must:

a) Analyze how a potential failure could affect high consequence areas;

b) Analyze the likelihood of failure due to each individual threat and each unique combination of threats that interact or simultaneously contribute to risk at a common location;

c) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

d) Evaluate the potential risk reduction associated with candidate risk reduction activities, such as preventive and mitigative measures, and reduced anomaly remediation and assessment intervals.

735) **Plastic transmission pipeline.** An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S and consider any threats unique to the integrity of plastic pipe, such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

736) **Actions to address particular threats.** Where an operator identifies any of the following threats, the operator must take the following actions to address the threat.

a) **Third party damage.** An operator must utilize the data integration required in paragraph 733) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. Where an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with section 16.18 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under section 16.11, or a reassessment under section 16.19, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

b) **Cyclic fatigue**. An operator must analyze and account for whether cyclic fatigue or other loading conditions (including ground movement, and suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The analysis must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the analysis together with the criteria used to determine the significance of the threat(s) to the covered segment to prioritize the integrity baseline assessment or reassessment. Failure stress pressure and crack growth analysis of cracks and crack-like defects must be conducted in accordance with section 14.9. An operator must monitor operating pressure cycles and periodically, but at least every 7 calendar years, with intervals not to exceed 90 months, determine where the cyclic fatigue analysis remains valid or where the cyclic fatigue analysis must be revised based on changes to operating pressure cycles or other loading conditions.

c) **Manufacturing and construction defects**. An operator must analyze the covered segment to determine and account for the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. The analysis must account for the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only where the covered segment has been subjected to hydrostatic pressure testing satisfying the criteria of section 11 of at least 1.25 times MAOP, and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent section 11 pressure test. Where any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment.

i) The pipeline segment has experienced a reportable incident, as defined in section 1.4, since its most recent successful section 11 pressure test, due to an original manufacturing-related defect, or a construction-, installation-, or fabrication-related defect;

ii) MAOP increases; or

iii) The stresses leading to cyclic fatigue increase.

d) **Electric Resistance Welded (ERW) pipe**. Where a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0 as defined in section 4.8, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding 5 years (including abnormal operation as defined in section 13.3, paragraph 485)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment. Pipe with seam cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with section 14.9.

e) **Corrosion.** Where an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in section 16.17), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under this regulation for testing and repair.

f) **Cracks.** Where an operator identifies any crack or crack-like defect (e.g., stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) on a covered pipeline segment that could adversely affect the integrity of the pipeline, the operator must evaluate, and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar characteristics associated with the crack or crack-like defect. Similar characteristics may include operating and maintenance histories, material properties, and environmental characteristics. An operator must establish a schedule for evaluating, and remediating, as necessary, the similar pipeline segments that is consistent with the operator's established operating and maintenance procedures under this part for testing and repair.

16.10 What must be in the baseline assessment plan?

An operator must include each of the following elements in its written baseline assessment plan:

737) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (See section 16.9)

738) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (See section 16.9). More than one method may be required to address all the threats to the covered pipeline segment;

739) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule;

740) Where applicable, a direct assessment plan that meets the requirements of sections 16.12, and depending on the threat to be addressed, of 16.13, 16.14, or 16.15; and

741) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

16.11 How is the baseline assessment to be conducted?

742) **Assessment methods.** An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See 16.9).

a) Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible. The use of internal inspection tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with section 10.25. In addition, an operator must analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

b) Pressure test conducted in accordance with section 11 of this regulation. The use of section 11 pressure testing is appropriate for threats such as internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, see section 1.7) to justify an extended reassessment interval in accordance with section 16.20.

c) Spike hydrostatic pressure test conducted in accordance with section 11.4. The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

d) Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

e) Guided wave ultrasonic testing (GWUT) as described in Appendix E. The use of GWUT is appropriate for internal and external pipe wall loss;

f) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only where appropriate for the threat and the pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in section 16.12 and with the applicable requirements specified in section 16.13, 16.14 and 16.15; or

g) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify URCA in advance of using the other technology in accordance with section 2.7.

743) **Prioritizing segments.** An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in section 16.9.

744) **Assessment for particular threats.** In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in section 16.9 , paragraph 736) to address particular threats that it has identified.

745) **Time period**. An operator must prioritize all the covered segments for assessment in accordance with section 16.9, paragraph 734) and paragraph 743) of this section.

746) **Newly identified areas**. When an operator identifies a new high consequence area (see 16.3), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

747) **Newly installed pipe.** An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this section within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph 742) b) of this section, to satisfy the requirement for a baseline assessment.

748) **Plastic transmission pipeline.** Where the threat analysis required in section 16.9, paragraph 706

on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of section 16.9. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

749) **Baseline assessments for pipeline segments with a reconfirmed MAOP**. An integrity assessment conducted in accordance with the requirements of section 13.17, paragraph 550) may be used as a baseline assessment under this section.

16.12 How is direct assessment used and for what threats?

750) **General**. An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this section. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC).

751) **Primary method.** An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—

a) Section 192.925 and ASME/ANSI B31.8S (incorporated by reference, see 1.7) section 6.4, and NACE SP0502 (incorporated by reference, see 1.7) , where addressing external corrosion (EC).

b) Section 192.927 and NACE SP0206 (incorporated by reference, see 1.7), where addressing internal corrosion (IC).

c) Section 192.929 and NACE SP0204 (incorporated by reference, see 1.7), where addressing stress corrosion cracking (SCC).

752) **Supplemental method.** An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in section 16.16.

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

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

754) **General requirements.** An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see 1.7), section 6.4, and in NACE SP0502 (incorporated by reference, see 1.7). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect inspection, direct examination, and post assessment. Where the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (16.9, paragraph 733)) to evaluate the covered segment for the threat of third party damage and to address the threat as required by 16.9, paragraph 736) a).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in section 16.20. (See Appendix D of NACE SP0502.)

16.14 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

755) **Definition**. Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO2, O2, hydrogen sulfide or other contaminants present in the gas.

756) **General requirements**. An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206 (incorporated by reference, see section 1.7). The Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) process described in this section applies only for a segment of pipe transporting normally dry natural gas (see section 1.4) and not for a segment with electrolytes normally present in the gas stream. Where an operator uses ICDA to assess a covered segment operating with electrolytes present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to address internal corrosion effectively and must notify URCA in accordance with section 2.7. In the event of a conflict between this section and NACE SP0206, the requirements in this section control.

757) **The ICDA plan.** An operator must develop and follow an ICDA plan that meets NACE SP0206 (incorporated by reference, see 1.7) and that implements all four steps of the DG-ICDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. The plan must identify the locations of all ICDA regions within covered segments in the transmission system. An ICDA region is a continuous length of pipe (including weld joints), uninterrupted by any significant change in water or flow characteristics, that includes similar physical characteristics or operating history. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located to complete the assessment of the covered segment.

a) **Preassessment**. An operator must comply with NACE SP0206 (incorporated by reference, see 1.7) in conducting the preassessment step of the ICDA process.

b) **Indirect inspection.** An operator must comply with NACE SP0206 (incorporated by reference, see 1.7), and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. An operator must explicitly document the results of its feasibility assessment as required by NACE SP0206, section 3.3 (incorporated by reference, see 1.7); where any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use actual pipeline-specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of the data used to make those calculations, including, but not limited to, gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossings, river crossings, drains, valves, drips, etc.), topographical data, and depth of cover. An operator must select locations for direct examination and establish the extent of pipe exposure needed (i.e., the size of the bell hole), to account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

c) **Detailed examination**. An operator must comply with NACE SP0206 (incorporated by reference, see 1.7) in conducting the detailed examination step of the ICDA process. When an operator first uses ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with the ICDA region and must perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques that can examine for internal corrosion or other threats that are being assessed. One location must be the low point (e.g., sag, drip, valve, manifold, dead-leg) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment, near the end of the ICDA region. Whenever corrosion is found during ICDA at any location, the operator must:

   i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with section 16.17 where the condition is in a covered segment, or in accordance with section 10.20 and 14.11 where the condition is not in a covered segment;

   ii) Expand the detailed examination program to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined in accordance with paragraph 757) c) of this section, two additional detailed examinations must be conducted within the covered segment; and

iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region in which the corrosion was found and remediate identified instances of internal corrosion in accordance with either sections 16.17 or 10.20 and 14.25, as appropriate.

d) **Post-assessment evaluation and monitoring.** An operator must comply with NACE SP0206 (incorporated by reference, see 1.7) in performing the post assessment step of the ICDA process. In addition to NACE SP0206, the evaluation and monitoring process must also include—

i) An evaluation of the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in section 16.20. An operator must carry out this evaluation within 1 year of conducting an ICDA;

ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (where the flow model cannot be validated, then ICDA is not feasible for the segment); and

iii) Continuous monitoring of each ICDA region that contains a covered segment where internal corrosion has been identified by using techniques such as coupons or ultrasonic (UT) sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this section and risk factors specific to the ICDA region.

At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7 1/2 months. Where an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions, and remediate the conditions the operator finds in accordance with sections 16.17 or 10.20 and 14.11, as applicable.

1. Conduct excavations of, and detailed examinations at, locations downstream from where the electrolytes might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of section 10.16; or

2. Assess the covered segment using another integrity assessment method allowed by this section.

e) **Other requirements.** The ICDA plan must also include the following:

i) Criteria an operator will apply in making key decisions (including, but not limited to, ICDA feasibility, definition of ICDA regions and sub-regions, and conditions requiring excavation) in implementing each stage of the ICDA process; and

ii) Provisions that the analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of section 16.17 may be limited to covered segments.

16.15 What are the requirements for using Direct Assessment for Stress Corrosion Cracking?

758) **Definition**. A Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipeline segment for the presence of stress corrosion cracking (SCC) by systematically gathering and analyzing excavation data from pipe having similar operational characteristics and residing in a similar physical environment.

759) **General requirements**. An operator using direct assessment as an integrity assessment method for addressing SCC in a covered pipeline segment must develop and follow an SCCDA plan that meets NACE SP0204 (incorporated by reference, see 1.7) and that implements all four steps of the SCCDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. As specified in NACE SP0204, SCCDA is complementary with other inspection methods for SCC, such as in-line inspection or hydrostatic testing with a spike test, and it is not necessarily an alternative or replacement for these methods in all instances. Additionally, the plan must provide for—

a) **Data gathering and integration**. An operator's plan must provide for a systematic process to collect and evaluate data for all covered pipeline segments to identify whether the conditions for SCC are present and to prioritize the covered pipeline segments for assessment in accordance with NACE SP0204, sections 3 and 4, and Table 1 (incorporated by reference, see 1.7). This process must also include gathering and evaluating data related to SCC at all sites an operator excavates while conducting its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204 (incorporated by reference, see 1.7) indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204, section 5.3 (incorporated by reference, see 1.7), and must include, at a minimum, all data listed in NACE SP0204, Table 2 (incorporated by reference, see 1.7). Further, the following factors must be analyzed as part of this evaluation:

i) 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, the presence or generation of carbon dioxide, or cathodic protection (CP);

ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments;

iii) The effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials;

iv) The effects of coatings that shield CP when disbonded from the pipe; and

v) Other factors that affect the mechanistic properties associated with SCC, including, but not limited to, historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

b) **Indirect inspection**. In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data.

c) **Direct examination**. In addition to NACE SP0204, the plan's procedures for direct examination must provide for an operator conducting a minimum of three direct examinations for SCC within the covered pipeline segment spaced at the locations determined to be the most likely for SCC to occur.

d) **Remediation and mitigation.** Where SCC is discovered in a covered pipeline segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

   i) Removing the pipe with SCC; remediating the pipe with a Type B sleeve; performing hydrostatic testing in accordance with paragraph ii) of this section; or by grinding out the SCC defect and repairing the pipe. Where an operator uses grinding for repair, the operator must also perform the following as a part of the repair procedure: nondestructive testing for any remaining cracks or other defects; a measurement of the remaining wall thickness; and a determination of the remaining strength of the pipe at the repair location that is performed in accordance with section 14.9 and that meets the design requirements of sections 4.6 and 4.7, as applicable. The pipe and material properties an operator uses in remaining strength calculations must be documented in traceable, verifiable, and complete records. Where such records are not available, an operator must base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with section 13.4, where applicable.

   ii) Performing a spike pressure test in accordance with section 11.4 based upon the class location of the pipeline segment. The MAOP must be no greater than the test pressure specified in section 11.4, paragraph 443) divided by: 1.39 for Class 1 locations and Class 2 locations that contain Class 1 pipe that has been uprated in accordance with section 13.7; and 1.50 for all other Class 2 locations and all Class 3 and Class 4 locations. An operator must repair any test failures due to SCC by replacing the pipe segment and re-testing the segment until the pipe passes the test without failures (such as pipe seam or gasket leaks, or a pipe rupture). At a minimum, an operator must repair pipe segments that pass the pressure test but have SCC present by grinding the segment in accordance with paragraph i) of this section.

e) **Post assessment.** An operator's procedures for post-assessment, in addition to the procedures listed in NACE SP0204, sections 6.3, "periodic reassessment," and 6.4, "effectiveness of SCCDA," must include the development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as the mechanistic behavior of identified cracking. An operator's reassessment intervals must comply with section 16.20. The plan must include the following factors, in addition to any factors the operator determines appropriate:

   i) The evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204, sections 5.3.5.7, 5.4, and 5.5 (incorporated by reference, see 1.7);

   ii) Conditions conducive to the creation of a carbonate-bicarbonate environment;

iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

iv) Operating temperature and pressure conditions, including operating stress levels on the pipe;

v) Cyclic loading conditions;

vi) Mechanistic conditions that influence crack initiation and growth rates;

vii) The effects of interacting crack clusters;

viii) The presence of sulfides; and

ix) Disbonded coatings that shield CP from the pipe.

16.16 How may Confirmatory Direct Assessment (CDA) be used?

760) An operator using the confirmatory direct assessment (CDA) method as allowed in section 16.19 must have a plan that meets the requirements of this section and of 16.13 (ECDA) and 16.14 (ICDA).

761) **Threats**. An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.

762) **External corrosion plan**. An operator's CDA plan for identifying external corrosion must comply with section 16.13 with the following exceptions.

a) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.

b) The procedures for direct examination and remediation must provide that—

i) All immediate action indications must be excavated for each ECDA region; and

ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.

763) **Internal corrosion plan.** An operator's CDA plan for identifying internal corrosion must comply with section 16.14 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

764) **Defects requiring near-term remediation.** Where an assessment carried out under paragraph 762) or 763) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE SP0502 (incorporated by reference, see 1.7), section 6.2 and 6.3.Where the defect requires immediate remediation, then the operator must reduce pressure consistent with section 16.17 until the operator has completed reassessment using one of the assessment techniques allowed in section 16.19.

16.17 What actions must be taken to address integrity issues?

765) **General requirements**. An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an

operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. Where documented data required for any analysis is not available, an operator must obtain the undocumented data through 13.4. Until documented material properties are available, the operator must use the conservative assumptions in either section 14.9, paragraph 618) b) or, where appropriate following a pressure test, in 14.9, paragraph 617) c).

a) **Temporary pressure reduction.**

i) Where an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must reduce the operating pressure to one of the following:

1. A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

2. A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

3. A level not exceeding the predicted failure pressure divided by 1.1.

ii) An operator must determine the predicted failure pressure in accordance with section 14.9. An operator must notify URCA in accordance with section 2.7 where it cannot meet the schedule for evaluation and remediation required under paragraph 767) or 768) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. The operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated.

b) **Long-term pressure reduction.** When a pressure reduction exceeds 365 calendar days, an operator must notify URCA under section 2.7 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

766) **Discovery of condition.** Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs 768) a) through c) of this section. An operator must promptly, but no later than 180 calendar days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period, the operator must notify URCA, in accordance with section 2.7, and provide an expected date when adequate information will become available. Notification to URCA does not alleviate an operator from the

discovery requirements of this paragraph.

767) **Schedule for evaluation and remediation.** An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph 768) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see 1.7), section 7, Figure 4.Where 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.

768) **Special requirements for scheduling remediation —**

a) **Immediate repair conditions.** An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 (incorporated by reference, see 1.7) in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph 765) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

i) A metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with section 14.9, paragraph 616) less than or equal to 1.1 times the MAOP at the location of the anomaly.

ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with section 14.9 , paragraph 583 demonstrate critical strain levels are not exceeded.

iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

iv) Metal loss preferentially affecting a detected longitudinal seam, where that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with section 14.9, paragraph 617) is less than 1.25 times the MAOP.

v) A crack or crack-like anomaly meeting any of the following criteria:

1. Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;
2. Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or
3. The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with section 14.9, paragraph 617), that is less than 1.25 times the MAOP.

vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

b) **One-year conditions.** Except for conditions listed in paragraphs a) and c) of this section, an operator must remediate any of the following within 1 year of discovery of the condition:

i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with section 14.9, paragraph 616) demonstrate critical strain levels are not exceeded.

ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless engineering analyses performed in accordance with section 14.9, paragraph 616) demonstrate critical strain levels are not exceeded.

iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1⁄3 of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with section 14.9, paragraph 616) demonstrate critical strain levels are not exceeded.

iv) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with section 14.9, paragraph 615), less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, see 1.7), section 7, Figure 4, in accordance with paragraph 767) of this section.

v) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with section 14.9, paragraph 582, of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with section 13.7, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

vi) Metal loss preferentially affecting a detected longitudinal seam, where that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with section 14.9, paragraph 617), is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with section 13.7, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with section 14.9, paragraph 617), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with section 13.7, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

c) **Monitored conditions.** An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but where an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:

i) A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), located between the 4 o'clock position and the 8 o'clock position (bottom 1⁄3 of the pipe), and for which engineering analyses of the dent, performed in accordance with section 14.9, paragraph 616), demonstrate critical strain levels are not exceeded.

ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and for which engineering analyses of the dent, performed in accordance with section 14.9, paragraph 616), demonstrate critical strain levels are not exceeded.

iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with section 14.9, paragraph 616),of the dent and girth or seam weld demonstrate that critical strain levels are not exceeded.

iv) A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with section 14.9, paragraph 616) demonstrate critical strain levels are not exceeded.

v) Metal loss preferentially affecting a detected longitudinal seam, where that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with section 14.9, paragraph 617), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with section 13.7, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with section 14.9, paragraph 617), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with section 13.7, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

769) **In situ direct examination of crack defects.** Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse

wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. “In situ” examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

16.18 What additional preventive and mitigative measures must an operator take?

770) **General requirements**.

a) An operator must take additional measures beyond those already required by this regulation to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Such additional measures must be based on the risk analyses required by section 16.9. Measures that operators must consider in the analysis, where necessary, to prevent or mitigate the consequences of a pipeline failure include, but are not limited to:

i) Correcting the root causes of past incidents to prevent recurrence;

ii) Establishing and implementing adequate operations and maintenance processes that could increase safety;

iii) Establishing and deploying adequate resources for the successful execution of preventive and mitigative measures;

iv) Installing automatic shut-off valves or remote-control valves;

v) Installing pressure transmitters on both sides of automatic shut-off valves and remote-control valves that communicate with the pipeline control center;

vi) Installing computerized monitoring and leak detection systems;

vii) Replacing pipe segments with pipe of heavier wall thickness or higher strength;

viii) Conducting additional right-of-way patrols;

ix) Conducting hydrostatic tests in areas where pipe material has quality issues or lost records;

x) Testing to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations, including material property tests from removed pipe that is representative of the in-service pipeline;

xi) Re-coating damaged, poorly performing, or disbonded coatings;

xii) Performing additional depth-of-cover surveys at roads, streams, and rivers;

xiii) Remediating inadequate depth-of-cover;

xiv) Providing additional training to personnel on response procedures and conducting drills with local emergency responders; and

xv) Implementing additional inspection and maintenance programs.

b) Operators must document the risk analysis, the preventive and mitigative measures considered, and the basis for implementing or not implementing any preventive and mitigative measures considered, in accordance with section 16.24, paragraph 794).

771) Third party damage and outside force damage—

a) **Third party damage.** An operator must enhance its damage prevention program, as required under section 13.9 of this regulation, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

i) Using qualified personnel (see 16.18) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non-covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under US CFR part 191 (incorporated by reference, see section 1.7).

iii) Participating in one-call systems in locations where covered segments are present.

iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. Where an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, see 1.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and section 16.17 any indication of coating holidays or discontinuity warranting direct examination.

b) **Outside force damage**. Where an operator determines that outside force (e.g., earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include increasing the frequency of aerial, foot or other methods of patrols; adding external protection; reducing external stress; relocating the line; or inline inspections with geospatial and deformation tools.

772) **Risk analysis for gas releases and protection against ruptures.** Where an operator determines, based on a risk analysis, that a rupture-mitigation valve (RMV) or alternative equivalent technology would be an efficient means of adding protection to a high-consequence area (HCA) in the event of a gas release, an operator must install the RMV or alternative equivalent technology. In making that

determination, an operator must, at least, evaluate the following factors—timing of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel. An RMV or alternative equivalent technology installed under this paragraph must meet all of the other applicable requirements in this section.

773) **Pipelines operating below 30% SMYS**. An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs a) and b) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs a), b) and c) of this section.

a) Apply the requirements in paragraphs 771) a) i) and iii) of this section to the pipeline; and

b) Either monitor excavations near the pipeline, or conduct patrols as required by 14.3 of the pipeline at bi-monthly intervals. Where an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine where mechanical damage has occurred.

c) Perform instrumented leak surveys using leak detector equipment at least twice each calendar year, at intervals not exceeding $7_{1/2}$ months. For unprotected pipelines or cathodically protected pipe where electrical surveys are impractical, instrumented leak surveys must be performed at least four times each calendar year, at intervals not exceeding $4_{1/2}$ months. Electrical surveys are indirect assessments that include close interval surveys, alternating current voltage gradient surveys, direct current voltage gradient surveys, or their equivalent.

774) **Plastic transmission pipeline.** An operator of a plastic transmission pipeline must apply the requirements in paragraphs 771) a) i), a) iii) and a) iv) of this section to the covered segments of the pipeline.

775) **Periodic evaluations.** Risk analyses and assessments conducted under paragraph 772) of this section must be reviewed by the operator and certified by a senior executive of the company, for operational matters that could affect rupture-mitigation processes and procedures. Review and certification must occur once per calendar year, with the period between reviews not to exceed 15 months, and must also occur within 3 months of an incident or safety-related condition, as those terms are defined at US CFR 191.3 and 191.23 (incorporated by reference, see section 1.7), respectively.

16.19 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

776) **General**. After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in section 16.20 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph 777) of this section.

777) **Evaluation**. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration

and risk assessment of the entire pipeline as specified in section 16.9. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 16.9, paragraph 735). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (see section 16.9), and decisions about remediation (16.17) and additional preventive and mitigative actions (16.18). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

778) **Assessment methods**. In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified on the covered segment (see 16.9).

a) **Internal inspection tools.** When performing an assessment using an in-line inspection tool, an operator must comply with the following requirements:

   i) Perform the in-line inspection in accordance with section 10.25;

   ii) Select a tool or combination of tools capable of detecting the threats to which the pipeline segment is susceptible such as corrosion, deformation and mechanical damage (e.g. dents, gouges and grooves), material cracking and crack-like defects (e.g. stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible; and

   iii) Analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

b) **Pressure test conducted in accordance with section 11 of this regulation.** The use of pressure testing is appropriate for threats such as: Internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, see section 1.7) to justify an extended reassessment interval in accordance with section 16.20.

c) **Spike hydrostatic pressure test in accordance with section 11.4**. The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as: Stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

d) Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation

(IWEX), radiography, or magnetic particle inspection (MPI);

e) Guided wave ultrasonic testing (GWUT) as described in Appendix E. The use of GWUT is appropriate for internal and external pipe wall loss;

f) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only where appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in section 16.12 and with the applicable requirements specified in section 16.13, 16.14, and 16.15;

g) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify URCA in advance of using the other technology in accordance with section 2.7; or

h) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than 7 calendar years. An operator using this reassessment method must comply with section 16.16.

779) **MAOP reconfirmation assessments.** An integrity assessment conducted in accordance with the requirements of section 13.17, paragraph 550) may be used as a reassessment under this section.

16.20 What are the required reassessment intervals?

780) An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

781) **Pipelines operating at or above 30% SMYS.** An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval where the operator submits written notice to URCA, in accordance with section 2.7, with sufficient justification of the need for the extension. Where an operator establishes a reassessment interval that is greater than 7 calendar years, the operator must, within the 7-calendar-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with section 16.16. The table that follows this section sets forth the maximum allowed reassessment intervals.

a) **Pressure test or internal inspection or other equivalent technology.** An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

i) Basing the interval on the identified threats for the covered segment (see 16.9) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by section 16.9; or

ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, see section 1.7), section 5, Table 3.

b) **External Corrosion Direct Assessment.** An operator that uses ECDA that meets the requirements of this section must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, see section 1.7).

c) **Internal Corrosion or SCC Direct Assessment**. An operator that uses ICDA or SCCDA in accordance with the requirements of this section must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;

ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and

iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.

782) **Pipelines Operating below 30% SMYS.** An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval where the operator submits written notice to URCA in accordance with section 2.7. The notice must include sufficient justification of the need for the extension. An operator must establish reassessment by at least one of the following—

a) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph 781) a) of this section except that the stress level referenced in paragraph 781) a) ii) of this section would be adjusted to reflect the lower operating stress level. Where an established interval is more than 7 calendar years, an operator must conduct by the seventh calendar year of the interval either a confirmatory direct assessment in accordance with section 16.16, or a low stress reassessment in accordance with section 16.21.

b) Reassessment by ECDA following the requirements in paragraph 781) b) of this section.

c) Reassessment by ICDA or SCCDA following the requirements in paragraph 781) c) of this section.

d) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with section 16.16, with reassessment by one of the methods listed in paragraphs a) through c) of this section by year 20 of the interval.

e) Reassessment by the low stress assessment method at 7-year intervals in accordance with section 16.21 with reassessment by one of the methods listed in paragraphs a) through c) of this section by year 20 of the interval.

f) The following table sets forth the maximum reassessment intervals. Also refer to Appendix D.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

Maximum Reassessment Interval

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years.(**)
Confirmatory Direct Assessment	7 years	7 years	7 years.
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in 16.21.

(*) A Confirmatory direct assessment as described in section 16.16 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

16.21 What is a low stress reassessment?

783) **General**. An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with section 16.20. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of section 16.10 and 16.11.

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

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

b) **Unprotected pipe or cathodically protected pipe where external corrosion assessments are impractical.** Where an external corrosion assessment is impractical on the covered segment an operator must—

i) Conduct leakage surveys as required by section 14.4 at 4-month intervals; and

ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

785) **Internal corrosion.** To address the threat of internal corrosion on a covered segment, an operator must—

a) Conduct a gas analysis for corrosive agents at least once each calendar year;

b) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and

c) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs a)-b) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

16.22 When can an operator deviate from these reassessment intervals?

786) **Waiver from reassessment interval in limited situations.** In the following limited instances, URCA may allow a waiver from a reassessment interval required by section 16.20 where URCA finds a waiver would not be inconsistent with pipeline safety.

a) **Lack of internal inspection tools.** An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment where internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

b) **Maintain product supply.** An operator may be able to justify a longer reassessment period for a covered segment where the operator demonstrates that it cannot maintain local product supply where it conducts the reassessment within the required interval.

787) **How to apply.** Where one of the conditions specified in paragraph 786) a) or b) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with U.S.C 49 60118(c) (incorporated by reference, see section 1.7), at least 180 calendar days before the end of the required reassessment interval, unless local product supply issues make the period impractical. Where local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

16.23 What methods must an operator use to measure program effectiveness?

788) **General**. An operator must include in its integrity management program methods to measure

whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, see section 1.7 of this regulation), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by US CFR 191.17 (incorporated by reference, see section 1.7).

789) **External Corrosion Direct assessment.** In addition to the general requirements for performance measures in paragraph 788) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of section 16.13.

16.24 What records must an operator keep?

790) An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this section. At minimum, an operator must maintain the following records for review during an inspection.

791) A written integrity management program in accordance with section 16.4;

792) Documents supporting the threat identification and risk assessment in accordance with section 16.9;

793) A written baseline assessment plan in accordance with section 16.10;

794) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;

795) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with section 16.18;

796) Schedule required by section 16.17 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.

797) Documents to carry out the requirements in section 16.12 through 16.15 for a direct assessment plan;

798) Documents to carry out the requirements in section 16.16 for confirmatory direct assessment;

799) Verification that an operator has provided any documentation or notification required by this section to be provided URCA has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

16.25 Where does an operator file a report?

800) An operator must file any report required by this section electronically to the URCA in accordance

with section 1.7 of this subchapter.

17 Gas Distribution Pipeline Integrity Management (IM)

17.1 What definitions apply to this section?

801) The following definitions apply to this section:

"Excavation Damage" means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

"Hazardous Leak" means a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

"Integrity Management Plan or IM Plan" means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this section.

"Integrity Management Program or IM Program" means an overall approach by an operator to ensure the integrity of its gas distribution system.

"Mechanical fitting" means a mechanical device used to connect sections of pipe. The term "Mechanical fitting" applies only to:

a) Stab Type fittings;

b) Nut Follower Type fittings;

c) Bolted Type fittings; or

d) Other Compression Type fittings.

"Small LPG Operator" means an operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

17.2 What do the regulations in this section cover?

802) **General.** Unless exempted in paragraph 803) of this section, this section prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this regulation, including liquefied petroleum gas systems. A gas distribution operator must follow the requirements in this section.

803) **Exceptions**. This section does not apply to:

a) Individual service lines directly connected to either a transmission pipeline and maintained in accordance with section 14.24, paragraph 663) and 664); and

b) Master meter systems.

17.3 What must a gas distribution operator (other than a small LPG operator) do to implement this section?

804) A gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in section 17.4.

17.4 What are the required elements of an integrity management plan?

A written integrity management plan must contain procedures for developing and implementing the following elements:

805) **Knowledge**. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

a) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

b) Consider the information gained from past design, operations, and maintenance.

c) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

d) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

e) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

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

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

808) **Identify and implement measures to address risks**. Determine and implement measures

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

809) **Measure performance, monitor results, and evaluate effectiveness.**

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

i) Number of hazardous leaks either eliminated or repaired as required by section 14.2, paragraph 592) (or total number of leaks where all leaks are repaired when found), categorized by cause;

ii) Number of excavation damages;

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

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

v) Number of hazardous leaks either eliminated or repaired as required by section 14.2, paragraph 592) (or total number of leaks where all leaks are repaired when found), categorized by material; and

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

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

811) **Report results.** Report, on an annual basis, the four measures listed in paragraphs 809) a) i) through iv) of this section, as part of the annual report required by section 2.2. An operator also must report the four measures to the state pipeline safety authority where a state exercises jurisdiction over the operator's pipeline.

17.5 What records must an operator keep?

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

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

813) An operator may propose to reduce the frequency of periodic inspections and tests required in this regulation on the basis of the engineering analysis and risk assessment required by this section.

814) An operator must submit its proposal to the URCA . The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

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

17.7 What must a small LPG operator do to implement this section?

816) **General**. A small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph 817) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

817) **Elements**. A written integrity management plan must address, at a minimum, the following elements:

a) **Knowledge**. The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

b) **Identify threats**. The operator must consider, at minimum, the following categories of threats (existing and potential): Corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.

c) **Rank risks**. The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.

d) **Identify and implement measures to mitigate risks.** The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.

e) **Measure performance, monitor results, and evaluate effectiveness**. The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.

f) **Periodic evaluation and improvement.** The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every 5 years. The operator must consider the results of the performance monitoring in these evaluations.

g) **Records.** The operator must maintain, for a period of at least 10 years, the following records:

i) A written IM plan in accordance with this section, including superseded IM plans;

ii) Documents supporting threat identification; and

iii) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

18 Appendix A - Qualification of Pipe and Components

I. List of Specifications

A. **Listed Pipe Specifications**

API Spec 5L—Steel pipe, "API Specification for Line Pipe" (incorporated by reference, see section 1.7).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference, see section 1.7).

ASTM A106/A-106M—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference, see section 1.7).

ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference, see section 1.7).

ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference, see section 1.7).

ASTM A671/A671M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference, see section 1.7).

ASTM A672/A672M-09—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference, see section 1.7).

ASTM A691/A691M-09—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures" (incorporated by reference, see section 1.7).

ASTM D2513"Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, see section 1.7).

ASTM D 2517-00—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, see section 1.7).

ASTM F2785-12 "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings" (PA-12) (incorporated by reference, see section 1.7).

ASTM F2817-10 "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference, see section 1.7).

ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings" (PA-11) (incorporated by reference, see section 1.7).

B. **Other Listed Specifications for Components**

ASME B16.40-2008 "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas

Distribution Systems" (incorporated by reference, see section 1.7).

ASTM D2513-Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, see section 1.7).

ASTM D 2517-00—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, see section 1.7).

ASTM F2785-12 "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings" (PA-12) (incorporated by reference, see section 1.7).

ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings" (PA-11) (incorporated by reference, see section 1.7).

ASTM F1055-98 (2006) "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (incorporated by reference, see section 1.7).

ASTM F1924-12 "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing" (incorporated by reference, see section 1.7).

ASTM F1948-12 "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing" (incorporated by reference, see section 1.7).

ASTM F1973-13 "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA 11) and Polyamide 12 (PA 12) Fuel Gas Distribution Systems" (incorporated by reference, see section 1.7).

ASTM F 2600-09 "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing" (incorporated by reference, see section 1.7).

ASTM F2145-13 "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing" (incorporated by reference, see section 1.7).

ASTM F2767-12 "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution" (incorporated by reference, see section 1.7).

ASTM F2817-10 "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference, see section 1.7).

II. Steel pipe of unknown or unlisted specification.

A. **Bending Properties**. For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53/A53M (incorporated by reference, see section 1.7), except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. **Weldability**. A girth weld must be made in the pipe by a welder who is qualified under section 6 of this regulation. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference, see section 1.7).Where the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code (ibr, see 192.7). The same number of chemical tests must be made as are required for testing a girth weld.

C. **Inspection**. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.+

D. **Tensile Properties.** Where the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L (incorporated by reference, see section 1.7). All test specimens shall be selected at random and the following number of tests must be performed:

Number of Tensile Tests—All Sizes

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

Where the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in section 3.3, paragraph 39).

III. **Steel pipe manufactured, to earlier editions of listed specifications**. Steel pipe manufactured, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this regulation where the following requirements are met:

A. **Inspection**. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. **Similarity of specification requirements**. The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. **Inspection or test of welded pipe.** On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with section 11 of this regulation to at least 1.25 times the maximum allowable operating pressure where it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure where it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under section 11 of this regulation, the test pressure must be maintained for at least 8 hours.

19 Appendix B - Qualification of Welders for Low Stress Level Pipe

I. **Basic test**. The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 1⁄8-inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered. A welder who successfully passes a butt-weld qualification test under this section shall be qualified to weld on all pipe diameters less than or equal to 12 inches.

II. **Additional tests for welders of service line connections to mains.** A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable where it shows a serious undercutting or where it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable where it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. **Periodic tests for welders of small service lines.** Two samples of the welder's work, each about 8 inches (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches (51 millimeters) on each side of the weld. Where the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. Where failure occurs adjacent to or in the weld metal, the weld is unacceptable. Where a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in subparagraph (1) of this paragraph.

20 Appendix C - Criteria for Cathodic Protection and Determination of Measurements

I. Criteria for cathodic protection—

A. **Steel, cast iron, and ductile iron structures.**

(1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half-cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.

(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. **Aluminum structures.**

(1) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II and IV of this appendix.

(2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(3) Notwithstanding the alternative minimum criteria in paragraphs (1) and (2) of this paragraph, aluminum, where cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half-cell, in accordance with section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum

structures in environments with a natural pH in excess of 8.

C. **Copper structures**. A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. **Metals of different anodic potentials**. A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. Where amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. Interpretation of voltage measurement. Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of section I of this appendix.

III. Determination of polarization voltage shift. The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of section I of this appendix.

IV. Reference half cells.

A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half-cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated cooper-copper sulfate half-cell. Two commonly used reference half cells are listed below along with their voltage equivalent to −0.85 volt as referred to a saturated copper-copper sulfate half cell:

(1) Saturated KCl calomel half cell: −0.78 volt.

(2) Silver-silver chloride half-cell used in sea water: −0.80 volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half-cell where its potential stability is assured and where its voltage equivalent referred to a saturated copper-copper sulfate half-cell is established.

21 Appendix D - Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

I. **Guidance on Determining a High Consequence Area**

To determine which segments of an operator's transmission pipeline system are covered for purposes of the integrity management program requirements, an operator must identify the high consequence areas. An operator must use method (i) or (i) from the definition in section 16.2 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. (Refer to figure E.I.A for a diagram of a high consequence area).

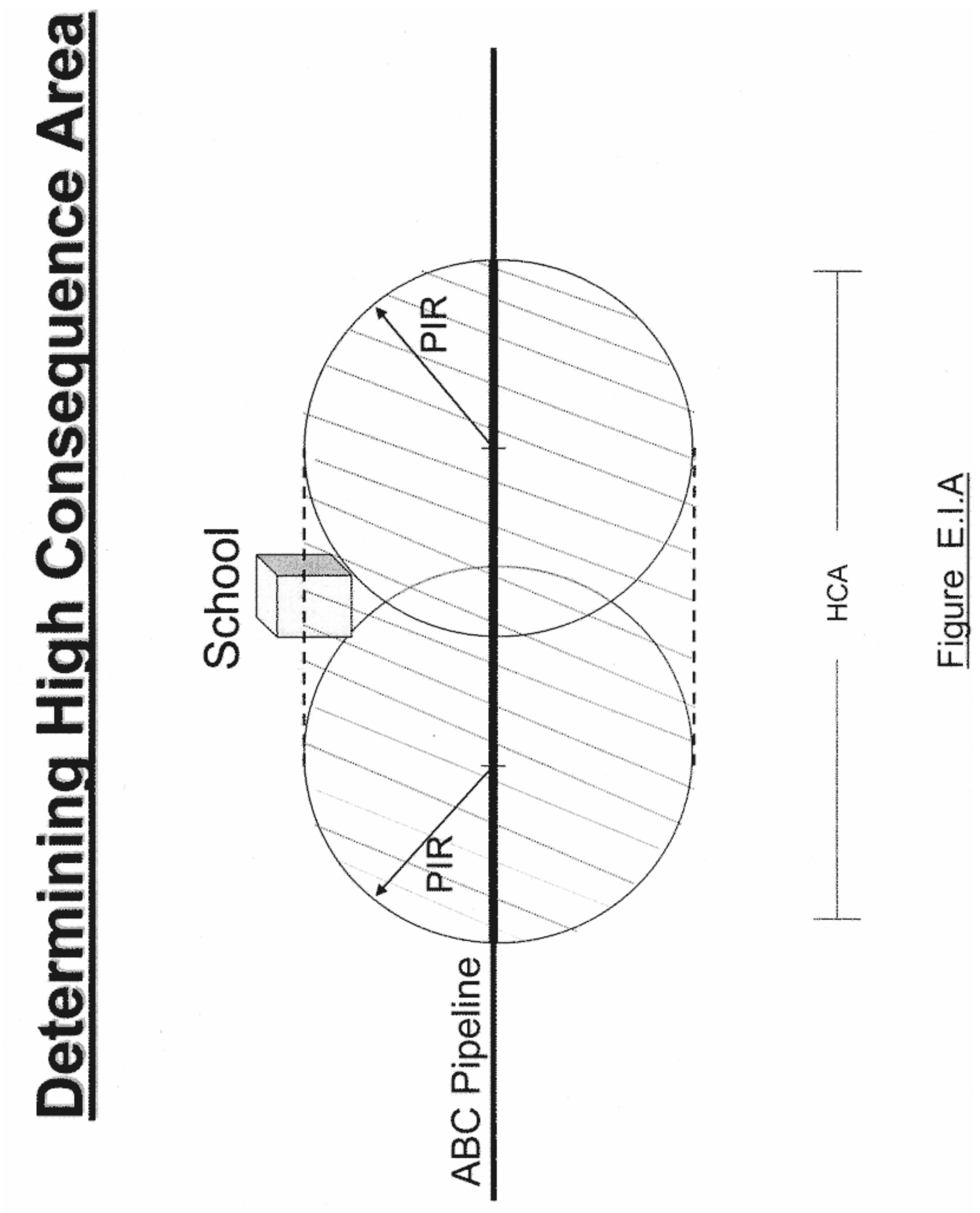

Figure E.I.A

II. **Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines**

a) Table E.II.1 gives guidance to help an operator implement requirements on additional preventive and mitigative measures for addressing time dependent and independent threats for a transmission pipeline operating below 30% SMYS not in an HCA (i.e. outside of potential impact circle) but located within a Class 3 or Class 4 Location.

b) Table E.II.2 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats for a transmission pipeline in an HCA.

c) Table E.II.3 gives guidance on preventative & mitigative measures addressing time dependent and independent threats for transmission pipelines that operate below 30% SMYS, in HCAs.

Table E.II.1: Preventive and Mitigative Measures for Transmission Pipelines Operating Below 30% SMYS not in an HCA but in a Class 3 or Class 4 Location

(Column 1) Threat	Existing 192 Requirements (Column 2) Primary	 (Column 3) Secondary	(Column 4) Additional (to 192 requirements) Preventive and Mitigative Measures
External Corrosion	455-(Gen. Post 1971), 457-(Gen. Pre-1971) 459-(Examination), 461-(Ext. coating) 463-(CP), 465-(Monitoring) 467-(Elect isolation), 469-Test stations) 471-(Test leads), 473-(Interference) 479-(Atmospheric), 481-(Atmospheric) 485-(Remedial), 705-(Patrol) 706-(Leak survey), 711 (Repair – gen.) 717-(Repair – perm.)	603-(Gen Oper'n) 613-(Surveillance)	For Cathodically Protected Transmission Pipeline: • Perform semi-annual leak surveys. For Unprotected Transmission Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impractical: • Perform quarterly leak surveys
Internal Corrosion	475-(Gen IC), 477-(IC monitoring) 485-(Remedial), 705-(Patrol) 706-(Leak survey), 711 (Repair – gen.) 717-(Repair – perm.)	53(a)-(Materials) 603-(Gen Oper'n) 613-(Surveillance)	• Perform semi-annual leak surveys.

Table E.II.2 Assessment Requirements for Transmission Pipelines in HCAs (Re-assessment intervals are maximum allowed)

	Re-Assessment Requirements (see Note 3)					
	At or above 50% SMYS		At or above 30% SMYS up to 50% SMYS		Below 30% SMYS	
Baseline Assessment Method (see Note 3)	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method
Pressure Testing	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	Pressure Test or ILI or DA				
		Repeat inspection cycle every 10 years	15(see Note 1)	Pressure Test or ILI or DA (see Note 1)		
				Repeat inspection cycle every 15 years	20	Pressure Test or ILI or DA
						Repeat inspection cycle every 20 years
In-Line Inspection	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	ILI or DA or Pressure Test				
		Repeat inspection cycle every 10 years	15(see Note 1)	ILI or DA or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	ILI or DA or Pressure Test

						Repeat inspection cycle every 20 years
Direct Assessment	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	DA or ILI or Pressure Test				
		Repeat inspection cycle every 10 years	15(see Note 1)	DA or ILI or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	DA or ILI or Pressure Test
						Repeat inspection cycle every 20 years

Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S

Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of P&M

Note 3: Operator may utilize "other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe"

Table E.II.3

Preventative & Mitigative Measures addressing Time Dependent and Independent Threats for Transmission Pipelines that Operate Below 30% SMYS , in HCAs

Threat	Existing 192 Requirements		Additional (to 192 requirements) Preventive & Mitigative Measures
	Primary	Secondary	
External Corrosion	455-(Gen. Post 1971) 457-(Gen. Pre-1971) 459-(Examination) 461-(Ext. coating) 463-(CP) 465-(Monitoring) 467-(Elect isolation)	603-(Gen Oper) 613-(Surveil)	For Cathodically Protected Trmn. Pipelines • Perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years. Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment. Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

External Corrosion	469-Test stations) 471-(Test leads) 473-(Interference) 479-(Atmospheric) 481-(Atmospheric) 485-(Remedial) 705-(Patrol) 706-(Leak survey) 711 (Repair – gen.) 717-(Repair – perm.)		For Unprotected Trmn. Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impracticable • Conduct quarterly leak surveys AND • Every 1-1/2 years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
Internal Corrosion	475-(Gen IC) 477-(IC monitoring) 485-(Remedial) 705-(Patrol) 706-(Leak survey) 711 (Repair – gen.) 717-(Repair – perm.)	53(a)-(Materials) 603-(Gen Oper) 613-(Surveil)	• Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCAs, • Periodic testing of fluid removed from pipelines. Specifically, once each calendar year from each storage field that may affect transmission pipelines in HCAs, AND • At least every 7 years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records.

3rd Party Damage	103-(Gen. Design) 111-(Design factor) 317-(Hazard prot) 327-(Cover) 614-(Dam. Prevent) 616-(Public educat) 705-(Patrol) 707-(Line markers) 711 (Repair – gen.) 717-(Repair – perm.)	615 –(Emerg Plan)	• Participation in state one-call system, • Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND • Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

22 Appendix E - Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

This appendix defines criteria which must be properly implemented for use of guided wave ultrasonic testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered “other technology” as described by 14.7, paragraph 606) g), section 16.11, paragraph 742) g), and 16.19, paragraph 778) d), for which OPS must be notified 90 calendar days prior to use in accordance with 16.11, paragraph 742) g) or 16.19, paragraph 778) d). GWUT in the “Go-No Go” mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested, or replaced prior to completing the integrity assessment on the carrier pipe.

I. **Equipment and Software: Generation**. The equipment and the computer software used are critical to the success of the inspection. Computer software for the inspection equipment must be reviewed and updated, as required, on an annual basis, with intervals not to exceed 15 months, to support sensors, enhance functionality, and resolve any technical or operational issues identified.

II. **Inspection Range.** The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general, the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.

III. **Complete Pipe Inspection.** To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double-ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. Where possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

IV. **Sensitivity.** The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than 5% of the cross sectional area (CSA).The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented. All defect indications in the “Go-No Go” mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

V. **Wave Frequency**. Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

VI. **Signal or Wave Type: Torsional and Longitudinal.** Both torsional and longitudinal waves must be used and use must be documented.

VII. **Distance Amplitude Correction (DAC) Curve and Weld Calibration.** The distance amplitude correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection. DAC curves provide a means for evaluating the cross-sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

VIII. **Dead Zone**. The dead zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

IX. **Near Field Effects**. The near field is the region beyond the dead zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

X. **Coating Type.** Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. Where an inspection is done and the required sensitivity is not achieved for the entire length of the pipe, then another type of assessment method must be utilized.

XI. **End Seal**. When assessing cased carrier pipe with GWUT, operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.

XII. **Weld Calibration to set DAC Curve.** Accessible welds, along or outside the pipeline segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used where welds along the pipeline segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used where welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. Where the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used where justified by a documented engineering analysis and evaluation.

XIII. **Validation of Operator Training.** Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:

A. Equipment operation,

B. field data collection, and

C. data interpretation on cased and buried pipe. Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment. A senior-level GWUT equipment operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A senior-level GWUT equipment operator must have additional training and experience, including training specific to cased and buried pipe, with a quality control program which that conforms to Section 12 of ASME B31.8S (for availability, see section 1.7).

XIV. **Training and Experience Minimums for Senior Level GWUT Equipment Operators:**

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)

- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XV. **Equipment: Traceable from vendor to inspection company.** An operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.

XVI. **Calibration Onsite.** The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated to a different casing or pipeline segment. Where on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVII. **Use on Shorted Casings (direct or electrolytic).** GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (see section 13.3) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures.

XVIII. **Direct examination of all indications above the detection sensitivity threshold.** The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe or other GWUT application. Where this cannot be accomplished, then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

Timing of direct examination of all indications above the detection sensitivity threshold. Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

Required Response to GWUT Indications

GWUT criterion	Operating pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50% SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of 5% CSA)	Replace or direct examination within 12 months, and instrumented leak survey once every 30 calendar days	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and maintain MAOP below the operating pressure at time of discovery	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of operating pressure at time of discovery.