Title 20—DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

PROPOSED AMENDMENT

20 CSR 4240-40.020 Incident, Annual, and Safety-Related Condition Reporting Requirements. The commission is amending sections (1), (2), (4), (5), (6), (7), (9), (10), (11) and (12).

PURPOSE: This amendment proposes to amend the rule to adopt additional portions of 49 CFR part 191 and makes clarification and editorial changes.

(1) Scope. (191.1)

(B) This rule does not apply to gathering of gas—

1. Through a pipeline that operates at less than zero (0) pound per square inch gauge (psig) (0 kPa); or

2. Through a pipeline that is not a regulated onshore gathering line (as determined in *[4 CSR 240]* **20 CSR** 4240-40.030(1)(E) (192.8)).

(2) Definitions. (191.3) As used in this rule and in the PHMSA Forms referenced in this rule—

(D) Federal incident means any of the following events:

1. An event that involves a release of gas from a pipeline, gas **from an underground natural gas storage facility, liquefied natural gas (LNG), liquefied petroleum gas, refrigerant gas, or gas from an LNG facility**, and that results in one (1) or more of the following consequences:

A. A death or personal injury necessitating inpatient hospitalization; or

B. Estimated property damage of fifty thousand dollars ($50,000) or more, including loss to the operator and others, or both, but excluding the cost of gas lost; or

C. Unintentional estimated gas loss of three (3) million cubic feet or more. *[or]*

2. An event that results in an emergency shutdown of an LNG facility or an underground natural gas storage facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident; or

*[2.]***3.** An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraph (2)(D)1. **or (2)(D)2.**;

(N) Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas, in or affecting **intrastate**, interstate, or foreign commerce; and

(4) Immediate Notice of Missouri Incidents.

(A) Within two (2) hours following discovery by the operator, or as soon thereafter as practicable if emergency efforts to protect life and property would be hindered, each gas operator must notify designated commission personnel by telephone of the following events within areas served by the operator:

1. An event that involves a release of gas involving the operator's actions or pipeline system, or where there is a suspicion by the operator that the event may involve a release of gas involving the operator's actions or pipeline system, and results in one (1) or more of the following consequences—

A. A death;

B. A personal injury involving medical care administered in an emergency room or health care facility, whether inpatient or outpatient, beyond initial treatment and prompt release after evaluation by a health care professional; or

C. Estimated property damage of ten thousand dollars ($10,000) or more, including loss to the gas operator or others, or both, and including the cost of gas lost; *[or]*

2. An event that is significant, in the judgement of the operator, even though it did not meet the criteria of paragraph (4)(A)1.; or

3. An event that is reported as a Federal incident under section (3).

(5) Report Submission Requirements. (191.7)

(B) Missouri Incident Reports.

1. This subsection applies to events that meet the criteria in subsection (4)(A) but are not a federal incident reported under subsection (5)(A). Within thirty (30) days of a telephone notification made under subsection (4)(A), each gas operator must submit **the applicable** U.S. Department of Transportation Form PHMSA F 7100.1, *[or]* PHMSA F 7100.2, *[as applicable,]* **or PHMSA F 7100.3** to designated commission personnel. Additional information required in subsections (6)(B) and (9)(B) for federal incidents is also required for these events.

2. The incident report forms for gas distribution systems (PHMSA F 7100.1, revised October 2014), *[and]* gas transmission and gathering pipeline systems (PHMSA F 7100.2, revised October 2014), **and LNG facilities (PHMSA F 7100.3, revised October 2014)** are incorporated by reference **in subsection (5)(G)**. *[The forms are published by the U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The forms are available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The PHMSA F 7100.1 form does not include any amendments or additions to the October 2014 version. The PHMSA F 7100.2 form does not include any amendments or additions to the October 2014 version.]*

(G) Forms Incorporated by Reference.

1. The following forms are incorporated by reference and made part of this rule.

A. U.S. Department of Transportation Form PHMSA F 1000.1, revised April 2019. The PHMSA F 1000.1 form is the Operator Identification (OPID) Assignment Request form and does not include any amendments or additions to the April 2019 version.

B. U.S. Department of Transportation Form PHMSA F 1000.2, revised April 2019. The PHMSA F 1000.2 form is the Operator Registry Notification form for reporting changes including operator name change, change in entity operating, shared safety program change, change in ownership for gas facilities, construction or rehabilitation of gas facilities, change in ownership for LNG, and construction for LNG. The PHMSA F 1000.2 form does not include any amendments or additions to the April 2019 version.

C. U.S. Department of Transportation Form PHMSA F 7100.1, revised October 2014. The PHMSA F 7100.1 form is the incident report form for gas distribution systems and does not include any amendments or additions to the October 2014 version.

D. U.S. Department of Transportation Form PHMSA F 7100.1-1, revised October 2018. The PHMSA F 7100.1-1 form is the annual report form for gas distribution systems and does not include any amendments or additions to the October 2018 version.

E. U.S. Department of Transportation Form PHMSA F 7100.1-2, revised October 2014. The PHMSA F 7100.1-2 form is the report form for mechanical fitting failures and does not include any amendments or additions to the October 2014 version.

F. U.S. Department of Transportation Form PHMSA F 7100.2, revised October 2014. The PHMSA F 7100.2 form is the incident report form for gas transmission and gathering pipeline systems and does not include any amendments or additions to the October 2014 version.

G. U.S. Department of Transportation Form PHMSA F 7100.2-1, revised October 2014. The PHMSA F 7100.2-1 form is the annual report form for gas transmission and gathering pipeline systems and does not include any amendments or additions to the October 2014 version.

H. U.S. Department of Transportation Form PHMSA F 7100.3, revised October 2014. The PHMSA F 7100.3 form is the incident report form for LNG facilities and does not include any amendments or additions to the October 2014 version.

I. U.S. Department of Transportation Form PHMSA F 7100.3-1, revised August 2017. The PHMSA F 7100.3-1 form is the annual report form for LNG facilities and does not include any amendments or additions to the August 2017 version.

J. U.S. Department of Transportation Form PHMSA 7100.4-1, approved August 2017. The PHMSA F 7100.4-1 form is the annual report form for underground natural gas storage facilities and does not include any amendments or additions to the August 2017 version.

2. The forms listed in paragraph (5)(G)1. are published by the U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The forms are available at www.phmsa.dot.gov/forms/pipeline-forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E).

(6) Distribution System—Federal Incident Report. (191.9)

(A) Except as provided in subsection (6)(C), each operator of a distribution pipeline system must submit U.S. Department of Transportation Form PHMSA F 7100.1 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). See the report submission requirements in subsection (5)(A). The incident report form (revised October 2014) is incorporated by reference *[and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the October 2014 version]* **in subsection (5)(G)**.

(7) Distribution System—Annual Report and Mechanical Fitting Failure Reports.

(A) Annual Report. (191.11)

1. Except as provided in paragraph (7)(A)3., each operator of a distribution pipeline system must submit an annual report for that system on U.S. Department of Transportation Form PHMSA F 7100.1-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A).

2. The annual report form (revised *[January 2017]* **October 2018**) is incorporated by reference *[and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the January 2017 version]* **in subsection (5)(G)**.

3. The annual report requirement in this subsection does not apply to a master meter system or to a petroleum gas system which serves fewer than one hundred (100) customers from a single source.

(B) Mechanical Fitting Failure Reports. (191.12)

1. Each mechanical fitting failure, as required by *[4 CSR 240]* **20 CSR 4240**-40.030(17)(E) (192.1009), must be submitted on a Mechanical Fitting Failure Report Form (U.S. Department of Transportation Form PHMSA F 7100.1-2). An operator must submit a mechanical fitting failure report for each mechanical fitting failure that occurs within a calendar year not later than March 15 of the following year *[(for example, all mechanical failure reports for calendar year 2012 must be submitted no later than March 15, 2013)]*. Alternatively, an operator may elect to submit its reports throughout the year. In addition, an operator must also report this information to designated commission personnel.

2. The Mechanical Fitting Failure Report Form (October 2014) is incorporated by reference *[and is published by the U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the October 2014 version]* **in subsection (5)(G)**.

(9) Transmission *[and Gathering]* Systems; **Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities**—Federal Incident Report. (191.15)

(A) Transmission *[and]* **or** Gathering. Each operator of a transmission or a gathering pipeline system must submit U.S. Department of Transportation Form PHMSA F 7100.2 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). See the report submission requirements in subsection (5)(A). The incident report form (revised October 2014) is incorporated by reference *[and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the October 2014 version]* **in subsection (5)(G)**.

(B) *[Supplemental Report. When additional related information is obtained after a report is submitted under subsection (9)(A), the operator must make a supplemental report, as soon as practicable, with a clear reference by date to the original report.]* **LNG. Each operator of a liquefied natural gas plant or facility must submit U.S. Department of Transportation Form PHMSA F 7100.3 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). See the report submission requirements in subsection (5)(A). The incident report form (revised October 2014) is incorporated by reference in subsection (5)(G).**

(C) Underground natural gas storage facility. Each operator of an underground natural gas storage facility must submit U.S. Department of Transportation Form PHMSA F 7100.2 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). The incident report form (revised October 2014) is incorporated by reference in subsection (5)(G).

(D) Supplemental Report. When additional related information is obtained after a report is submitted under subsection (9)(A), (9)(B), or (9)(C), the operator must make a supplemental report as soon as practicable with a clear reference by date to the original report.

(10) Transmission *[and Gathering]* Systems; **Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities**—Annual Report. (191.17)

(A) Transmission *[and]* **or** Gathering. Each operator of a transmission or a gathering pipeline system must submit an annual report for that system on U.S. Department of Transportation Form PHMSA

F 7100.2-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A). The annual report form (revised October 2014) is incorporated by reference *[and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the October 2014 version]* **in subsection (5)(G).**

(B) *[(Reserved)]* **LNG. Each operator of a liquefied natural gas facility must submit an annual report for that system on U.S. Department of Transportation Form PHMSA F 7100.3-1 This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A). The annual report form (revised August 2017) is incorporated by reference in subsection (5)(G).**

(C) Underground natural gas storage facility. Each operator of an underground natural gas storage facility must submit an annual report on U.S. Department of Transportation Form PHMSA 7100.4-1 by March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A). The annual report form (August 2017) is incorporated by reference in subsection (5)(G).

(11) National Registry of Pipeline and LNG Operators (191.22)

(A) OPID Request.

1. Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, underground natural gas storage facility, LNG plant, or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must complete an OPID Assignment Request (U.S. Department of Transportation Form PHMSA F 1000.1) through the National Registry of Pipeline and LNG Operators at http://portal.phmsa.dot.gov/pipeline unless an alternative reporting method is authorized in accordance with subsection (5)(D). A copy of each submission to PHMSA must also be submitted concurrently to designated commission personnel—see addresses in subsection (5)(E).

2. The OPID Assignment Request form (*[May 2015]* **April 2019**) is incorporated by reference *[and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the May 2015 version]* **in subsection (5)(G).**

(C) Changes. Each operator of a gas pipeline, gas pipeline facility, underground natural gas storage facility, LNG plant, or LNG facility must notify PHMSA electronically through the National Registry of Pipeline and LNG Operators at http://portal.phmsa.dot.gov/pipeline of certain events. A copy of each online notification must also be submitted concurrently to designated commission personnel—see addresses in subsection (5)(E).

1. An operator must notify PHMSA of any of the following events not later than sixty (60) days before the event occurs:

A. Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs ten (10) million dollars or more. If sixty- (60-) day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

B. Construction of ten (10) or more miles of a new or replacement pipeline;

C. Construction of a new LNG plant or LNG facility;

D. Construction of a new underground natural gas storage facility or the abandonment, drilling, or well workover (including replacement of wellhead, tubing, or a new casing) of an injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility;

E. Reversal of product flow direction when the reversal is expected to last more than thirty (30) days. This notification is not required for pipeline systems already designed for bi-directional flow; or

F. A pipeline converted for service under *[4 CSR 240]* **20 CSR 4240**-40.030(1)(H) (192.14), or a change in commodity as reported on the annual report as required by section (10) (191.17).

2. An operator must notify PHMSA of any of the following events not later than sixty (60) days after the event occurs:

A. A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this rule covering pipeline facilities operated under multiple OPIDs;

B. A change in the name of the operator;

C. A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, underground natural gas storage facility, or LNG facility;

D. The acquisition or divestiture of fifty (50) or more miles of a pipeline or pipeline system subject to *[4 CSR 240]* **20 CSR 4240**-40.030;

E. The acquisition or divestiture of an existing LNG plant or LNG facility subject to 49 CFR Part 193; or

F. The acquisition or divestiture of an existing underground natural gas storage facility subject to 49 CFR part 192.

(D) Reporting. An operator must use the OPID issued by PHMSA for all reporting requirements covered under *[4 CSR 240]* **20 CSR 4240**-40.020, *[and]* 40.030, **40.033, and 40.080,** and for submissions to the National Pipeline Mapping System.

(12) Reporting Safety-Related Conditions. (191.23)

(A) Except as provided in subsection (12)(B), each operator must report in accordance with section (13) (191.25) the existence of any of the following safety-related conditions involving facilities in service:

1. In the case of the pipeline (other than an LNG facility) that operates at a hoop stress of twenty percent (20%) or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure and localized corrosion pitting to a degree where leakage might result;

2. In the case of an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well, general corrosion that has reduced the wall thickness to less than that required for the maximum well operating pressure, and localized corrosion pitting to a degree where leakage might result;

*[2.]***3.** Unintended movement or abnormal loading by environmental causes, *[for instance,]* **such as** an earthquake, landslide or flood, that impairs the serviceability of a pipeline **or the structural integrity or reliability of an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility, or LNG facility that contains, controls, or processes gas or LNG;**

4. Any crack or other material defect that impairs the structural integrity or reliability of an underground natural gas storage facility or LNG facility that contains, controls, or processes gas or LNG;

*[3.]***5.** Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of twenty percent (20%) or more of its specified minimum yield strength **or underground natural gas storage facility, including injection, withdrawal, monitoring, or observations well for an underground**

natural gas storage facility;

*[4.]***6.** Any malfunction or operating error that causes the pressure of *[a]*:–

A. A pipeline to rise above its maximum allowable operating pressure plus the buildup allowed for operation of pressure limiting or control devices;

B. An underground natural gas storage facility to rise above its maximum well operating pressure plus the margin (build-up) allowed for operation of pressure limiting or control devices; or

C. An LNG facility that contains or processes gas or LNG to rise above its working pressure plus the margin (build-up) allowed for operation of pressure limiting or control devices.

*[5.]***7.** A leak in a pipeline **or an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility, or LNG facility that contains or processes gas or LNG** that constitutes an emergency; *[and]*

8. Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank; and

*[6.]***9.** Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a twenty percent (20%) or more reduction in operating pressure or shutdown of operation of a pipeline **or an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility, or an LNG facility that contains or processes gas or LNG.**

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. Original rule filed Feb. 5, 1970, effective Feb. 26, 1970. For intervening history, please consult the Code of State Regulations. Amended: Filed Dec. 12, 2019.

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions in excess of five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will not cost private entities in excess of five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file a statement in support of or in opposition to the proposed amendment with the Missouri Public Service Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received no later than February 14, 2020, and should include a reference to Commission Case No. GX-2020-0112. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/efis.asp. A public hearing is scheduled for 10:00 a.m., February 24, 2020, in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment, and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

Title 20—DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

PROPOSED AMENDMENT

20 CSR 4240-40.030 Safety Standards—Transportation of Gas by Pipeline. The commission is amending sections (1), (2), (3), (4), (6), (7), (8), (9), (10), (12), (13), (14), (16), (17) and amending the Agency Note, Appendix A, Appendix B, Appendix C, Appendix D and Appendix E.

PURPOSE: This amendment modifies the rule to address amendments of 49 CFR part 192 promulgated between October 2017 and December 2018, and makes clarification and editorial changes.

AGENCY NOTE: This rule is similar to the Minimum Federal Safety Standards contained in 49 CFR part 192, Code of Federal Regulations. Parallel citations to Part 192 are provided for gas operator convenience and to promote public safety. Appendix E, contained in this rule, is a Table of Contents for [4 CSR 240] ***20 CSR 4240-40.030.***

(1) General.

(B) Definitions. (192.3) as used in this rule—

1. Abandoned means permanently removed from service;
2. Active corrosion means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety;
3. Administrator means the Administrator of the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation to whom authority in the matters of pipeline safety have been delegated by the Secretary of the United States Department of Transportation, or his or her delegate;
4. Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters;
5. Building means any structure that is regularly or periodically occupied by people;
6. Commission means the Missouri Public Service Commission;
7. Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility;
8. Controller means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a supervisory control and data acquisition (SCADA) system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility;
9. Customer meter means the meter that measures the transfer of gas from an operator to a consumer;
10. Designated commission personnel means the pipeline safety program manager at the address contained in *[4 CSR 240]* **20 CSR 4240**-40.020(5)(E) for correspondence;
11. Distribution line means a pipeline other than a gathering or transmission line;
12. 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, except that other indirect examination tools/methods can be used for an electrical survey included in the federal regulations in 49 CFR part 192, subpart O and appendix E (incorporated by reference in section (16));
13. Feeder line means a distribution line that has a maximum allowable operating pressure (MAOP) greater than 100 psi (689 kPa) gauge that produces hoop stresses less than twenty percent (20%) of specified minimum yield strength (SMYS);
14. Follow-up inspection means an inspection performed after a repair procedure has been completed in order to determine the effectiveness of the repair and to ensure that all hazardous leaks in the area are corrected;
15. Fuel line means the customer-owned gas piping downstream from the outlet of the customer meter or operator-owned pipeline, whichever is farther downstream;

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

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

18. High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than an equivalent to fourteen inches (14") water column;

19. Hoop stress means the stress in a pipe wall acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe produced by the pressure in the pipe;

20. Listed specification means a specification listed in subsection I. of Appendix B, which is included herein (at the end of this rule);

21. Low-pressure distribution system means a distribution system in which the gas pressure in the main is less than or equal to an equivalent of fourteen inches (14") water column;

22. Main means a distribution line that serves as a common source of supply for more than one (1) service line;

23. Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of one (1) year;

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

25. Municipality means a city, village, or town;

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

27. Person means any individual, firm, joint venture, partnership, corporation, association, county, state, municipality, political subdivision, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative of them;

28. 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) gauge at 100°F (38°C);

29. PHMSA means the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation;

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

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

32. 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;

33. 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;

34. Reading means the highest sustained reading when testing in a bar hole or opening without induced ventilation;

35. Service line means a distribution line that transports gas from a common source of supply to an individual customer, to two (2) adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter;

36. 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 (1) customer or multiple customers through a meter header or manifold;

37. 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 paragraph (3)(D)2. (192.107[b]);

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

39. Sustained reading means the reading taken on a combustible gas indicator unit after adequately venting the test hole or opening;

40. Transmission line means a pipeline, other than a gathering line, that—

A. Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center (A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.);

B. Operates at a hoop stress of twenty percent (20%) or more of SMYS; or

C. Transports gas within a storage field;

41. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas *[in Missouri]*, **in or affecting intrastate, interstate, or foreign commerce;**

42. Tunnel means a subsurface passageway large enough for a man to enter;

43. Vault or manhole means a subsurface structure that a man can enter;

44. 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;

*[44.]***45.** Welder means a person who performs manual or semi-automatic welding;

*[45.]***46.** Welding operator means a person who operates machine or automatic welding equipment; and

*[46.]***47.** Yard line means an underground fuel line that transports gas from the service line to the customer's building. If multiple buildings are being served, building means the building nearest to the connection to the service line. For purposes of this definition, if aboveground fuel line piping at the meter location is located within five feet (5') of a building being served by that meter, it will be considered to the customer's building and no yard line exists. At meter locations where aboveground fuel line piping is located greater than five feet (5') from the building(s) being served, the underground fuel line from the meter to the entrance into the nearest building served by that meter will be considered the yard line and any other lines are not considered yard lines.

(D) Incorporation By Reference of the Federal Regulation at 49 CFR 192.7. (192.7)

1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 201*[7]***8, and the subsequent amendment 192-124 (published in *Federal Register* on November 20, 2018, page 83 FR 58694)**, the federal regulation at 49 CFR 192.7 is incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR 192.7.

2. The *Code of Federal Regulations* and the *Federal Register* are published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 201*[7]***8** version of 49 CFR part 192 is available at *[www.gpo.gov/fdsys/search/showcitation.action]* **https://www.govinfo.gov/#citation. The *Federal Register* publication on page 83 FR 58694 is available at https://www.govinfo.gov/content/pkg/FR-2018-11-20/pdf/2018-24925.pdf.**

3. The regulation at 49 CFR 192.7 provides a listing of the documents that are incorporated by reference partly or wholly in 49 CFR part 192, which is the federal counterpart and foundation for this rule. All incorporated materials are available for inspection from several sources, including the following sources:

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

B. The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, go to the NARA website at www.archives.gov/federal-register/cfr/ibr-locations.html or call 202-741-6030 or 866-272-6272; and

C. Copies of standards incorporated by reference can also be purchased or are otherwise made available from the respective standards-developing organizations listed in 49 CFR 192.7.

4. Federal amendment 192-94 (published in Federal Register on June 14, 2004, page 69 FR 32886) moved the listing of incorporated documents to 49 CFR 192.7 from 49 CFR part 192—Appendix A, which is now "Reserved." This listing of documents was in Appendix A to this rule prior to the 2008 amendment of this rule. As of the 2008 amendment, Appendix A to this rule is also "Reserved" and included herein.

(E) Gathering Lines. (192.8 and 192.9)

1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 201*[7]***8, and the subsequent amendment 192-124 (published in *Federal Register* on November 20, 2018, page 83 FR 58694,** the federal regulations at 49 CFR 192.8 and 192.9 are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR 192.8 and 192.9.

2. The *Code of Federal Regulations* is published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 201*[7]***8** version of 49 CFR part 192 is available at *[www.gpo.gov/fdsys/search/showcitation.action]* **https://www.govinfo.gov/#citation. The *Federal Register* publication on page 83 FR 58694 is available at https://www.govinfo.gov/content/pkg/FR-2018-11-20/pdf/2018-24925.pdf.**

3. The regulations at 49 CFR 192.8 and 192.9 provide the requirements for gathering lines. The requirements for offshore lines are not applicable to Missouri.

(H) Conversion to Service Subject to this Rule. (192.14)

1. Except as provided in paragraph (1)(H)4., a steel pipeline previously used in service not subject to this rule qualifies for use under this rule if 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 if 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 rule; and

D. The pipeline must be tested in accordance with section (10) to substantiate the maximum allowable operating pressure permitted by section (12).

2. Each operator must keep for the life of the pipeline a record of investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (1)(H)1.

3. An operator converting a pipeline from service not previously covered by this rule must notify PHMSA and designated commission personnel sixty (60) days before the conversion occurs as required by *[4 CSR 240]* **20 CSR 4240**-40.020(11).

4. This paragraph lists situations where steel pipe may not be converted to service subject to this rule.

A. Steel yard lines that are not cathodically protected must be replaced under subsection (15)(C).

B. Buried steel fuel lines that are not cathodically protected may not be converted to a pipeline as defined in subsection (1)(B), such as a service line or main.

C. Buried steel pipes that are not cathodically protected may not be converted to a service line.

D. Buried steel pipes that are not cathodically protected may not be converted to a main in Class 3 and Class 4 locations.

(J) Filing of Required Plans, Procedures, and Programs.

1. Each operator shall submit to designated commission personnel all plans, procedures, and programs required by this rule (to include welding and joining procedures, construction standards, control room management procedures, corrosion control procedures, damage prevention program, distribution integrity management plan, emergency procedures, public education program, operator qualification program, replacement programs, transmission integrity management program, and procedural manual for operations, maintenance, and emergencies). In addition, each change must be submitted to designated commission personnel within twenty (20) days after the change is made.

2. All operators under the pipeline safety jurisdiction of the Missouri Public Service Commission must establish and submit welding procedures, joining procedures, and construction specifications and standards to designated commission personnel before construction activities begin. All other plans, procedures and programs required by rules *[4 CSR 240]* **20 CSR 4240**-40.020, *[4 CSR 240]* **20 CSR 4240**-40.030, and *[4 CSR 240]* **20 CSR 4240**-40.080 must be established and submitted to designated commission personnel before the system is put into operation.

3. A written plan for drug and alcohol testing in accordance with *[4 CSR 240]* **20 CSR 4240**-40.080 must be submitted to designated commission personnel.

(2) Materials.

(D) Plastic Pipe. (192.59)

1. New polyethylene pipe is qualified for use under this rule if—

A. It is manufactured in accordance with a listed specification; *[and]*

B. It is resistant to chemicals with which contact may be anticipated*[.]***; and**

C. It is free of visual defects.

2. Used plastic pipe is qualified for use under this rule if—

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 *[natural]* 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.

3. For the purpose of subparagraphs (2)(D)1.A. and 2.A., 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 if 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.

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

(E) Marking of Materials. (192.63)

1. Except as provided in paragraphs (2)(E)4. **and (2)(E)5.**, each valve, fitting, length of pipe, and other component must be marked*[—]*

[A. As] as prescribed in the specification or standard to which it was manufactured.*[, except that thermoplastic pipe and fittings made of plastic materials other than polyethylene must be marked in accordance with ASTM D 2513-87 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)); or*

B. To indicate size, material, manufacturer, pressure rating, temperature rating and, as appropriate, type, grade, and model.]

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

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

4. Paragraph (2)(E)1. does not apply to items manufactured before November 12, 1970, that meet all of the following:

A. The item is identifiable as to type, manufacturer, and model; and

B. Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

5. All plastic pipe and components must also meet the following requirements:

A. All markings on plastic pipe prescribed in the listed specification and the requirements of subparagraph (2)(E)5.B. must be repeated at intervals not exceeding two (2) feet;

B. Plastic pipe and components manufactured after December 31, 2019 must be marked in accordance with the listed specification; and

C. All physical markings on plastic pipelines prescribed in the listed specification and subparagraph (2)(E)5.B. must be legible until the time of installation.

(G) Storage and Handling of Plastic Pipe and Associated Components. (192.67) 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.

(3) Pipe Design.

(I) Design of Plastic Pipe. (192.121)

1. *[Subject to the limitations of subsection (3)(J), the design pressure for plastic pipe is]* **Design Formula. Design formulas for plastic pipe are** determined in accordance with either of the following formulas:

$$P = 2\,S\,\frac{t}{(D-t)} \times [0.32]\mathrm{DF}$$

$$P = \frac{2\,S}{(SDR-1)} \times [0.32]\mathrm{DF}$$

where

P=Design pressure, psi (kPa) gauge;

S=For thermoplastic pipe, the hydrostatic design base (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-3/2008, *HDB/PDB/SDB/MRS Policies* (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D));

t = Specified wall thickness, inches (millimeters);

D = Specified outside diameter, inches (millimeters); and

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

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

2. General Requirements for Plastic Pipe and Components.

A. The design pressure may not exceed a gauge pressure of 100 psi (689 kPa) gauge for plastic pipe.

B. Plastic pipe may not be used where operating temperatures of the pipe will be:

(I) Below -20 °F (-29 °C), or -40 °F (-40 °C) if 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 subsection is determined.

C. The wall thickness for thermoplastic 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 in 49 CFR 192.7 and adopted in subsection (1)(D)).

3. Polyethylene (PE) Pipe Requirements.

A. The federal regulation at 49 CFR 192.121(c)(1) is not adopted in this rule. (This federal regulation permits higher design pressures for certain types of PE pipe.)

B. For PE pipe produced after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

(I) The design pressure does not exceed 100 psig;

(II) The material designation code is PE2708 or PE4710;

(III) The pipe has a nominal size (IPS or CTS) of 12 inches or less; and

(IV) The wall thickness for a given outside diameter is not less than that listed in the following table:

PE Pipe: Minimum Wall Thickness and SDR Values		
Pipe Size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
½" CTS	0.09	7
¾" CTS	0.09	9.7
½" IPS	0.09	9.3
¾" IPS	0.095	11
1" CTS	0.119	11
1" IPS	0.119	11
1 ¼" IPS	0.151	11
1 ½" 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

4. The federal regulations at 49 CFR 192.121(d) through (f) are not adopted in this rule. (Those federal regulations address design requirements for types of plastic pipe other than PE pipe.)

(J) *[Design Limitations for Plastic Pipe.]* **Reserved** (192.123)

[1. The design pressure may not exceed a gauge pressure of 100 psi (689 kPa) gauge for plastic pipe used in—

A. Distribution systems; or

B. Classes 3 and 4 locations.

2. Plastic pipe may not be used where operating temperatures of the pipe will be—

A. Below -20 °F (-29 °C), or -40 °F (-40 °C) if 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

B. Above the temperature at which the HDB used in the design formula under subsection (3)(I) is determined.

3. The wall thickness for thermoplastic pipe may not be less than 0.062 inches (1.57 millimeters).

4. The federal regulations at 49 CFR 192.123(e) and (f) are not adopted in this rule. (Those federal regulations permit *higher design pressures for certain types of thermoplastic pipe.)]*

(4) Design of Pipeline Components.

(B) General Requirements. (192.143)

1. 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, if 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.

2. The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in section (9).

3. Except for excess flow valves, each plastic pipeline component installed after April 22, 2019, must be able to withstand operating pressures and other anticipated loads in accordance with a listed specification.

(D) Valves. (192.145)

1. Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Specification 6D (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), 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.

2. 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; and

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 one and one-half (1.5) times the maximum service rating;

(II) After the shell test, the seat must be tested to a pressure not less than one and one-half (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.

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

4. No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding eighty percent (80%) 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 eighty percent (80%) of the pressure ratings for comparable steel valves at their listed temperature, if —

A. The temperature-adjusted service pressure does not exceed 1,000 psi (7 MPa) gauge; and

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

5. 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.

6. Except for excess flow valves, plastic valves installed after April 22, 2019, 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.

(F) Standard Fittings. (192.149)

1. 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 rule or their equivalent.

2. 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.

3. Plastic fittings installed after April 22, 2019, must meet a listed specification.

(AA) *[Design Pressure of Plastic Fittings. (192.191) Thermoplastic fittings for plastic pipe must conform to ASTM D2513-99 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) for plastic materials other than polyethylene or ASTM D2513-09A (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) for polyethylene plastic materials.]* **Risers Installed After January 22, 2019. (192.204)**

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

2. Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973-13 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

3. 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.

(6) Joining of Materials Other Than by Welding.

(F) Plastic Pipe (192.281)

1. 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.

2. 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 D*[2513-99]* **2564-12 for PVC** (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)); and

C. The joint may not be heated **or cooled** to accelerate the setting of the cement.

3. Heat-fusion joints. Each heat-fusion joint on *[plastic]* **a PE** pipe **or component, except for electrofusion joints,** must comply **with ASTM F2620-12 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))** 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 *[piping]* **pipe or component**, compresses the heated ends together, and holds the pipe in proper alignment *[while the plastic hardens]* **in accordance with the appropriate procedure qualified under subsection (6)(G)**;

B. A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the *[joint]* **pipe or component** uniformly and simultaneously to *[essentially]* **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 *[joined utilizing]* **made using** the equipment and techniques *[of]* **prescribed by** the fitting*[s]* manufacturer or **using** equipment and techniques shown, by testing joints to the requirements of part (6)(G)1.A.(III), to be *[at least]* equivalent *[to those]* **or better than the requirements** of the fitting*[s]* manufacturer; and

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

4. 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; *[and]*

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; and

D. All mechanical joints or fittings installed after April 22, 2019, 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 if tested in accordance with the applicable standard.

(G) Plastic Pipe—Qualifying Joining Procedures. (192.283)

1. Heat fusion, solvent cement, and adhesive joints. Before any written procedure established under paragraph (6)(B)2. 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 made according to the procedure to the following tests, **as applicable**:

A. The *[burst]* test requirements of—

(I) In the case of thermoplastic pipe, *[paragraph 6.6 (]* **based on the pipe material,** the Sustained Pressure Test*[)]* or the *[paragraph 6.7 (]*Minimum Hydrostatic Burst *[Pressure) of ASTM D2513-99 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) for plastic materials other than polyethylene or ASTM D2513-09A (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) for polyethylene plastic materials;]***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) *(Reserved)*; *[or]*

(III) In the case of electrofusion fittings for polyethylene 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 in 49 CFR 192.7 and adopted in subsection (1)(D));

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. If failure initiates outside the joint area, the procedure qualifies for use; and

C. For procedures intended for nonlateral pipe connections, *[follow the tensile test requirements of ASTM D638 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)),except that the test may be conducted at ambient temperature and humidity]* **perform testing in accordance with a listed specification**. If the test specimen elongates no less than twenty-five percent (25%) or failure initiates outside the joint area, the procedure qualifies for use.

2. Mechanical joints. Before any written procedure established under paragraph (6)(B)2. is used for making mechanical plastic pipe joints *[that are designed to withstand tensile forces]*, the procedure must be qualified *[by subjecting five (5) specimen joints made according to the procedure to the following tensile test:]* **in accordance with a listed specification based upon the pipe material.**

[A. Use an apparatus for the test as specified in ASTM D638 (except for conditioning), (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D));

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

C. The speed of testing is 0.20 inches (5.0 mm) per minute, plus or minus twenty-five percent (25%);

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

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

F. Each specimen that fails at the grips must be retested using new pipe; and

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

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

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

(H) Plastic Pipe—Qualifying Persons to Make Joints. (192.285)

1. 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 (6)(H)2.

2. 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 (1) of the test methods listed under paragraph (6)(G)1. (192.283[a]), **or for polyethylene heat fusion joints (except for electrofusion joints) visually inspected and tested in accordance with ASTM F2620-12 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) 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 three (3) longitudinal straps, each of which is—

(a) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(b) Deformed by bending, torque, or impact and, if failure occurs, it must not initiate in the joint area.

3. A person must be requalified under an applicable procedure once each calendar year at intervals not exceeding fifteen (15) months, or after any production joint is found unacceptable by testing under subsection (10)(G). (192.513)

4. 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 subsection.

(7) General Construction Requirements for Transmission Lines and Mains.

(G) Bends and Elbows. (192.313)

1. Each field bend in steel pipe, other than a wrinkle bend made in accordance with subsection (7)(H) (192.315), 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; and

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 twelve inches (12") (305 millimeters) or less in outside diameter or has a diameter-to-wall thickness ratio less than seventy (70).

2. 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.

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

4. 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.

(K) Installation of Plastic Pipe. (192.321)

1. Plastic pipe must be installed below ground level except as provided by paragraphs (7)(K)7., *[and]* (7)(K)8., **and (7)(K)9.**

2. Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gastight metal pipe and fittings that are adequately protected from corrosion.

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

4. *[Thermoplastic]* **Plastic** pipe *[that is not encased]* must have a minimum wall thickness *[of 0.090 inches (0.090") (2.29 millimeters), except that pipe with an outside diameter of 0.875 inches (0.875") (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inches (0.062") (1.58 millimeters)]* **in accordance with (3)(I).**

5. Plastic pipe that is not encased must have an electrically conductive 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.

6. 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.

7. Uncased plastic pipe may be temporarily installed aboveground 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 two (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; and

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

8. 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 subsection (3)*[(J)]***(I).**

9. 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; and

C. Installations of risers at regulator stations must meet the design requirements of (4)(AA).

(P) Installation of Plastic Pipelines by Trenchless Excavation. (192.329) Plastic pipelines installed by trenchless excavation must comply with the following:

1. 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; and

2. For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined in subsection (1)(B), to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

(8) Customer Meters, Service Regulators, and Service Lines.

(J) Service Lines—General Requirements for Connections to Main Piping. (192.367)

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

2. Compression-type connection to main. Each compression-type service line to main connection must—

A. Be designed and installed to effectively sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; *[and]*

B. If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system*[.]***; and**

C. If 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 if tested in accordance with the applicable standard.

(M) Service Lines—Plastic. (192.375)

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

A. It may be installed in accordance with paragraph (7)(K)7.; and

B. It may terminate aboveground level and outside the building, if—

(I) The aboveground level part of the plastic service line is protected against deterioration and external damage; *[and]*

(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 (4)(AA).

2. Plastic service lines shall not be installed inside a building.

3. Plastic pipe that is installed in a below grade vault or pit must be completely encased in gastight metal pipe and fittings that are adequately protected from corrosion.

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

5. Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches (0.090"), except that pipe with an outside diameter of 0.875 inches (0.875") or less may have a minimum wall thickness of 0.062 inches (0.062").

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

7. For requirements pertaining to installation of plastic service lines by trenchless excavation, see subsection (8)(R). (192.376)

(P) Excess Flow Valve Installation. (192.383)

1. Definitions for subsection (8)(P).

A. 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.

B. 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.

C. 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 (1) single-family residence.

2. Installation required. An excess flow valve (EFV) installation must comply with the performance standards in subsection (8)(O). After April 14, 2017, each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated:

A. A single service line to one (1) single family residence;

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

C. A branched service line to a single family residence installed off a previously installed single family residence service line that does not contain an EFV;

D. Multifamily residences with known customer loads not exceeding **one thousand standard cubic feet per hour** (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 **one thousand standard cubic feet per hour** (1,000 SCFH), at the time of meter installation, based on installed meter capacity.

3. Exceptions to excess flow valve installation requirement. An operator need not install an excess flow valve if one (1) or more of the following conditions are present:

A. The service line does not operate at a pressure of ten (10) psi gauge 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 residence;

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

D. An EFV meeting performance standards in subsection (8)(O) is not commercially available to the operator.

4. Customer's right to request an EFV. Existing service line customers who desire an EFV on service lines not exceeding **one thousand standard cubic feet per hour** (1,000 SCFH) and who do not qualify for one (1) of the exceptions in paragraph (8)(P)3. may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.

5. 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 (8)(P)3. and (8)(P)5.E., 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, website 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 if 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 if a service line customer requests installation of an EFV and the load does not exceed **one thousand standard cubic feet per hour** (1,000 SCFH) and the conditions of paragraph (8)(P)3. are not present, the operator must install an EFV at a mutually agreeable date*[.]***; and**

E. Operators of master-meter systems may continuously post a general notification in a prominent location frequented by customers.

6. Operator evidence of customer notification. An operator must make a copy of the notice or notices currently in use available during inspections conducted by designated commission personnel.

7. Reporting. Except for operators of master meter systems, each operator must report the EFV measures detailed in the annual report required by *[4 CSR 240]* **20 CSR 4240**-40.020(7)(A).

(R) Installation of Plastic Service Lines by Trenchless Excavation. (192.376) Plastic service lines installed by trenchless excavation must comply with the following:

1. 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; and

2. For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined in subsection (1)(B), to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

(9) Requirements for Corrosion Control.

(D) External Corrosion Control—Buried or Submerged Pipelines Installed After July 31, 1971. (192.455)

1. Except as provided in paragraphs (9)(D)2., *[and]* 5.**, and 6.,** each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

A. It must have an external protective coating meeting the requirements of subsection (9)(G) (192.461); and

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

2. An operator need not comply with paragraph (9)(D)1., if 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 five (5) years beyond installation, corrosion during the five- (5-) year period of service of the pipeline will not be detrimental to public safety.

3. Notwithstanding the provisions of paragraph (9)(D)2., if a pipeline is externally coated, it must be cathodically protected in accordance with subparagraph (9)(D)1.B.

4. Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of eight (8), unless tests or experience indicate its suitability in the particular environment involved.

5. This subsection 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 leaking caused by localized corrosion pitting.

6. Electrically isolated metal alloy fittings installed after April 22, 2019, that do not meet the requirements of paragraph (9)(D)5. must be cathodically protected, and must be maintained in accordance with the operator's integrity management plan.

(10) Test Requirements.

(G) Test Requirements for Plastic Pipelines. (192.513)

1. Each segment of a plastic pipeline must be tested in accordance with this subsection.

2. The test procedure must ensure discovery of all potentially

hazardous leaks in the segment being tested.

3. The test pressure must be at least one hundred fifty percent (150%) of the maximum allowable operating pressure or fifty (50) psi (345 kPa) gauge, whichever is greater. However, the maximum test pressure may not be more than *[three (3)]* **two and one half (2.5)** times the pressure determined under subsection (3)(I), at a temperature not less than the pipe temperature during the test.

4. 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.

(12) Operations.

(C) Procedural Manual for Operations, Maintenance, and Emergencies. (192.605)

1. 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 that are not exempt under subparagraph (12)(C)3.E., the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding fifteen (15) months, but at least once each calendar year. This manual must be prepared before initial operations of a pipeline system commence and appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

2. Maintenance and normal operations. The manual required by paragraph (12)(C)1. must include procedures for the following, if applicable, to provide safety during maintenance and normal operations:

A. Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this section and sections (13) and (14);

B. Controlling corrosion in accordance with the operations and maintenance requirements of section (9);

C. Making construction records, maps, and operating history available to appropriate operating personnel;

D. Gathering of data needed for reporting incidents under *[4 CSR 240]* **20 CSR 4240**-40.020 in a timely and effective manner;

E. Starting up and shutting down any part of a pipeline in a manner designed to assure operation within the MAOP limits prescribed by this rule, 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. Inspecting periodically to ensure that operating pressures are appropriate for the class location;

J. 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;

K. Systematically and routinely testing and inspecting 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 that, if 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 a safe operating condition and has adequate capacity;

L. Continuing observations during all routine activities including, but not limited to, meter reading and cathodic protection work, for the purpose of detecting potential leaks by observing vegetation and odors. Potential leak indications must be recorded and responded to in accordance with section (14);

M. Testing and inspecting of customer-owned gas piping and equipment in accordance with subsection (12)(S);

N. Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under subparagraph (12)(J)1.C. specifically apply to these reports; and

O. Implementing the applicable control room management procedures required by subsection (12)(T).

3. Abnormal operation. For transmission lines the manual required by paragraph (12)(C)1. 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 could cause 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; and

E. The requirements of this paragraph (12)(C)3. do not apply to natural gas distribution operations that are operating transmission lines in connection with their distribution system.

4. Safety-related conditions. The manual required by paragraph (12)(C)1. 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 commission's reporting requirements.

5. Surveillance, emergency response, and accident investigation. The procedures required by paragraph (12)(H)1. and subsections (12)(J) and (L) (192.613[a], 192.615 and 192.617) must be included in the manual required by paragraph (12)(C)1.

(D) Qualification of Pipeline Personnel.

1. Scope. (192.801)

A. This subsection prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility. This subsection applies to all individuals who perform covered tasks, regardless of whether they are employed by the operator, a contractor, a subcontractor, or any other entity performing covered tasks on behalf of the operator.

B. For the purpose of this subsection, a covered task is an activity, identified by the operator, that—

(I) Is performed on a pipeline facility;

(II) Is an operations, maintenance, or emergency-response task;

(III) Is performed as a requirement of this rule; and

(IV) Affects the operation or integrity of the pipeline.

2. Definitions. (192.803)

A. 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:

(I) Indicate a condition exceeding design limits;

(II) Result in a hazard(s) to persons, property, or the environment; or

(III) Require an emergency response.

B. Evaluation (or evaluate) means a process consisting of training and examination, established and documented by the operator, to determine an individual's ability to perform a covered task and to demonstrate that an individual possesses the knowledge and skills under paragraph (12)(D)4. After initial evaluation for paragraph (12)(D)4., subsequent evaluations for paragraph (12)(D)4. can consist of examination only. The examination portion of this process may be conducted by one (1) or more of the following:

(I) Written examination;

(II) Oral examination;

(III) Hands-on examination, which could involve observation supplemented by appropriate queries. Observations can be made during:

(a) Performance on the job;

(b) On the job training; or

(c) Simulations.

C. Qualified means that an individual has been evaluated and can:

(I) Perform assigned covered tasks; and

(II) Recognize and react to abnormal operating conditions.

3. Qualification program. (192.805) Each operator shall have and follow a written qualification program. The program shall include provisions to:

A. Identify covered tasks;

B. 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;

C. Ensure through evaluation that individuals performing covered tasks are qualified and have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities;

D. Allow individuals that are not qualified pursuant to this subsection to perform a covered task if directed and observed by an individual that is qualified;

E. Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident meeting the Missouri reporting requirements in *[4 CSR 240]* **20 CSR 4240**-40.020(4)(A);

F. Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

G. Communicate changes, including changes to rules and procedures, that affect covered tasks to individuals performing those covered tasks and their supervisors, and incorporate those changes in subsequent evaluations;

H. Identify the interval for each covered task at which evaluation of the individual's qualifications is needed, with a maximum interval of thirty-nine (39) months;

I. Evaluate an individual's possession of the knowledge and skills under paragraph (12)(D)4. at intervals not to exceed thirty-nine (39) months;

J. Ensure that covered tasks are—

(I) Performed by qualified individuals; or

(II) Directed and observed by qualified individuals; and

K. Submit each program change to designated commission personnel as required by subsection (1)(J).

4. Personnel to whom this subsection applies must possess the knowledge and skills necessary to—

A. Follow the requirements of this rule that relate to the covered tasks they perform;

B. Carry out the procedures in the procedural manual for operations, maintenance, and emergencies established under subsection (12)(C) (192.605) that relate to the covered tasks they perform;

C. Utilize instruments and equipment that relate to the covered task they perform in accordance with manufacturer's instructions;

D. Know the characteristics and hazards of the gas transported, including flammability range, odorant characteristics, and corrosive properties;

E. Recognize potential ignition sources;

F. Recognize conditions that are likely to cause emergencies, including equipment or facility malfunctions or failure and gas leaks, predict potential consequences of these conditions, and take appropriate corrective action;

G. Take steps necessary to control any accidental release of gas and to minimize the potential for fire or explosion; and

H. Know the proper use of firefighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated pipeline emergency condition.

5. Each operator shall continue to meet the training and annual review requirements regarding the operator's emergency procedures in subparagraph (12)(J)2.B., in addition to the qualification program required in paragraph (12)(D)3.

6. Each operator shall provide instruction to the supervisors or designated persons who will determine when an evaluation is necessary under subparagraph (12)(D)3.F.

7. Each operator shall select appropriately knowledgeable individuals to provide training and to perform evaluations. Where hands-on examinations and observations are used, the evaluator should possess the required knowledge to ascertain an individual's ability to perform covered tasks and react to abnormal operating conditions that might occur while performing those tasks.

8. Record keeping. (192.807) Each operator shall maintain records that demonstrate compliance with this subsection.

A. Qualification records shall include:

(I) Identification of the qualified individual(s);

(II) Identification of the covered tasks the individual is qualified to perform;

(III) Date(s) of current qualification; and

(IV) Qualification method(s).

B. 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 (5) years.

9. General. (192.809)

A. Operators must have a written qualification program by April 27, 2001. The program must be available for review by designated commission personnel.

B. Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

C. After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

(G) Change in Class Location— Confirmation or Revision of Maximum Allowable Operating Pressure. (192.611) If 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 (1) of the following three (3) paragraphs:

1. If the segment involved has been previously tested in place for a period of not less than eight (8) hours, 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 seventy-two percent (72%) of SMYS of the pipe in Class 1 and 2 locations, sixty percent (60%) of SMYS in Class 3 locations or fifty percent (50%) of SMYS in Class 4 locations;

2. 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 rule for new segments of pipelines in

the existing class location; or

3. The segment of pipeline involved must be tested in accordance with the applicable requirements of section (10), 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; and

B. The corresponding hoop stress may not exceed seventy-two percent (72%) of the SMYS of the pipe in Class 1 **and** 2 locations, sixty percent (60%) of SMYS in Class 3 locations or fifty percent (50%) of the SMYS in Class 4 locations.

4. The maximum allowable operating pressure confirmed or revised in accordance with this subsection may not exceed the maximum allowable operating pressure established before the confirmation or revision.

5. Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this subsection does not preclude the application of subsections (11)(B) and (C). (192.553 and 192.555)

6. Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under subsection (12)(F) must be completed within twenty-four (24) months of the change in class location. Pressure reduction under paragraph (12)(G)1. or 2. within the twenty-four- (24-) month period does not preclude establishing a maximum allowable operating pressure under paragraph (12)(G)3., at a later date.

(M) Maximum Allowable Operating Pressure—Steel or Plastic Pipelines. (192.619 and 192.620)

1. Except as provided in paragraph (12)(M)3., no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

A. The design pressure of the weakest element in the segment, determined in accordance with sections (3) and (4). However, for steel pipe in pipelines being converted under subsection (1)(H) or uprated under section (11), if any variable necessary to determine the design pressure under the design formula in subsection (3)(C) is unknown, one (1) of the following pressures is to be used as design pressure:

(I) Eighty percent (80%) of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), reduced by the appropriate factor in part (12)(M)1.B.(II); or

(II) If the pipe is twelve and three-quarter inches (12 3/4") (three hundred twenty-four (324) mm) or less in outside diameter and is not tested to yield under this paragraph, two hundred (200) psi (one thousand three hundred seventy-nine (1379) kPa) gauge;

B. The pressure obtained by dividing the highest pressure to which the segment was tested after construction or uprated as follows:

(I) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5; and

(II) For steel pipe operated at one hundred (100) psi (six hundred eighty-nine (689) kPa) gauge or more, the test pressure is divided by a factor determined in accordance with the following table:

Class	Factors[1], segment -		
Location	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under subsection (1)(H) (192.14)
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1]For segments installed, uprated, or converted after July 31, 1977 that are located on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

C. The highest actual operating pressure to which the segment was subjected during the five (5) years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested in accordance with subparagraph (12)(M)1.B. after the applicable date in the third column or the segment was uprated in accordance with section (11);

Pipeline Segment	Pressure Date	Test date
Onshore gathering line that first became subject to 49 CFR 192.8 and 192.9 after April 13, 2006 (see subsection (1)(E)).	March 15, 2006, or date line becomes subject to this rule, whichever is later.	Five (5) years preceding applicable date in second column.
Onshore transmission line that was a gathering line not subject to 49 CFR 192.8 and 192.9 before March 15, 2006 (see subsection (1)(E)).	March 15, 2006	March 15, 2001
All other pipelines.	July 1, 1970	July 1, 1965

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

2. No person may operate a segment of pipeline to which this subsection applies unless overpressure protective devices are installed for the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with subsection (4)(CC). (192.195)

3. The requirements on pressure restrictions in this subsection do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the five (5) years preceding the applicable date in the second column of the table in subparagraph (12)(M)1.C. An operator must still comply with subsection (12)(G).

4. No person may operate a pipeline at a pressure that results in a hoop stress greater than seventy-two percent (72%) of SMYS.

*[4.]*5. Alternative maximum allowable operating pressure for certain steel pipelines. (192.620) The federal regulations at 49 CFR 192.620 are not adopted in this rule.

(T) Control Room Management. (192.631)

1. General.

A. This subsection 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 subsection, except as follows. For each control room where an operator's activities are limited to either or both of distribution with less than two hundred fifty thousand (250,000) services or transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (12)(T)4. (regarding fatigue), (12)(T)9. (regarding compliance validation), and (12)(T)10. (regarding compliance and deviations).

B. The procedures required by this subsection must be integrated, as appropriate, with operating and emergency procedures required by subsections (12)(C) and (12)(J). An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraph (12)(T)2.; subparagraphs (12)(T)3.E. and (12)(T)4.B. and C.; and paragraphs (12)(T)6. and (12)(T)7. must be implemented no later than October 1, 2011. The procedures required by subparagraphs (12)(T)3.A.–D. and (12)(T)4.A. and D.; and paragraph (12)(T)5. must be implemented no later than August 1, 2012. The training procedures required by paragraph (12)(T)8. must be implemented no later than August 1, 2012, except that any training required by another paragraph or subparagraph of this subsection must be implemented no later than the deadline for that paragraph or subparagraph.

2. 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 if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

C. A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others;

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.

3. 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 in 49 CFR 192.7 and adopted in (1)(D)) 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 fifteen (15) months;

D. Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed fifteen (15) months; and

E. Establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

4. 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 (8) 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 if necessary for the safe operation of a pipeline facility.

5. 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 fifteen (15) months;

D. Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding fifteen (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 fifteen (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 subparagraphs (12)(T)5.A.–E.

6. 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.

7. 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 federal incidents that must be reported pursuant to *[4 CSR 240]* **20 CSR 4240**-40.020 to determine if control room actions contributed to the event and, if 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*[.]***; and**

B. Include lessons learned from the operator's experience in the training program required by this subsection.

8. 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 fifteen (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. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018.

9. Compliance validation. Operators must submit their procedures to designated commission personnel per subsection (1)(J).

10. Compliance and deviations. An operator must maintain for review during inspection—

A. Records that demonstrate compliance with the requirements of this subsection; and

B. Documentation to demonstrate that any deviation from the procedures required by this subsection was necessary for the safe operation of a pipeline facility.

(13) Maintenance.

(AA) Repair of Plastic Pipe. **(192.720)** Each leak, imperfection, or damage that impairs the serviceability of a plastic pipe must be removed, except that heat fusion patching saddles may be used to repair holes that have been tapped into the main for service installations, and full-encirclement heat fusion couplings may be used to repair and reinforce butt fusion joints. These patching saddles and couplings shall not be used for the repair of any imperfections or third-party damage sustained by the plastic pipe.

(CC) Joining Plastic Pipe by Heat Fusion; Equipment Maintenance and Calibration. (192.756) 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.

(14) Gas Leaks.

(C) Leak Classifications. The leak classifications in this subsection apply to pipelines, and do not apply to fuel lines. The definitions for "pipeline," "fuel line," "reading," "sustained reading," "building," "tunnel," and "vault or manhole" are included in subsection (1)(B). The definition for "reading" is the highest sustained reading when testing in a bar hole or opening without induced ventilation. Thus, the leak classification examples involving a gas reading do not apply to outside pipelines located aboveground. Even though the leak classifications do not apply to fuel lines, an operator must respond immediately to each notice of an inside leak or odor as required in paragraphs (12)(J)1., (14)(B)1., and (14)(B)2. In addition, the requirements in paragraph (12)(S)3. apply to fuel lines that are determined to be unsafe.

1. Class 1 leak is a gas leak which, due to its location and/or magnitude, constitutes an immediate hazard to a building and/or the general public. A Class 1 leak requires immediate corrective action. Examples of Class 1 leaks are: a gas fire, flash, or explosion; broken gas facilities such as contractor damage, main failures or blowing gas in a populated area; an indication of gas present in a building emanating from operator-owned facilities; a gas reading equal to or above the lower explosive limit in a tunnel, sanitary sewer, or confined area; gas entering a building or in imminent danger of doing so; and any leak which, in the judgment of the supervisor at the scene, is regarded as immediately hazardous to the public and/or property. When venting at or near the leak is the immediate corrective action taken for Class 1 leaks where gas is detected entering a building, the leak may be reclassified to a Class 2 leak if the gas is no longer entering the building, nor is in imminent danger of doing so. However, the leak shall be rechecked daily and repaired within fifteen (15) days. Leaks of this nature, if not repaired within five (5) days, may need to be reported as a safety-related condition, as required in *[4 CSR 240]* **20 CSR** **4240**-40.020(12) and (13). (191.23 and 191.25)

2. Class 2 leak is a leak that does not constitute an immediate hazard to a building or to the general public, but is of a nature requiring action as soon as possible. The leak of this classification must be rechecked every fifteen (15) days, until repaired, to determine that no immediate hazard exists. A Class 2 leak may be properly reclassified to a lower leak classification within fifteen (15) days after the initial investigation. Class 2 leaks due to readings in sanitary sewers, tunnels, or confined areas must be repaired or properly reclassified within fifteen (15) days after the initial investigation. All other Class 2 leaks must be eliminated within forty-five (45) days after the initial investigation, unless it is definitely included and scheduled in a rehabilitation or replacement program to be completed within a period of one (1) year, in which case the leak must be rechecked every fifteen (15) days to determine that no immediate hazard exists. Examples of Class 2 leaks are: a leak from a transmission line discernible twenty-five feet (25') or more from the line and within one hundred feet (100') of a building; any reading outside a building at the foundation or within five feet (5') of the foundation; any reading greater than fifty percent (50%) gas-in-air located five to fifteen feet (5'–15') from a building; any reading below the lower explosive limit in a tunnel, sanitary sewer, or confined area; any reading equal to or above the lower explosive limit in a vault, catch basin, or manhole other than a sanitary sewer; or any leak, other than a Class 1 leak, which in the judgment of the supervisor at the scene, is regarded as requiring Class 2 leak priority.

3. Class 3 leak is a leak that does not constitute a hazard to property or to the general public but is of a nature requiring routine action. These leaks must be repaired within five (5) years and be rechecked twice per calendar year, not to exceed six and one-half (6 1/2) months, until repaired or the facility is replaced. Examples of Class 3 leaks are: any reading of fifty percent (50%) or less gas-in-air located between five and fifteen feet (5'–15') from a building; any reading located between fifteen and fifty feet (15'–50') from a building, except those defined in Class 4; a reading less than the lower explosive limit in a vault, catch basin, or manhole other than a sanitary sewer; or any leak, other than a Class 1 or Class 2 which, in the judgment of the supervisor at the scene, is regarded as requiring Class 3 priority.

4. Class 4 leak is a confined or localized leak which is completely nonhazardous. No further action is necessary.

(16) Pipeline Integrity Management for Transmission Lines.

(A) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 201*[5]*8, the federal regulations in 49 CFR part 192, subpart O and in 49 CFR part 192, appendix E are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to subpart O and appendix E to 49 CFR part 192.

(B) The *Code of Federal Regulations* and the *Federal Register* are published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 201*[5]*8 version of 49 CFR part 192 is available at www.gpo.gov/fdsys/search/showcitation.action.

(D) When sending a notification or filing a report with PHMSA in accordance with this section, a copy must also be submitted concurrently to designated commission personnel. This is consistent with the requirement in *[4 CSR 240]* **20 CSR 4240**-40.020(5)(A) for reports to PHMSA.

(F) For the purposes of this section, the following substitutions should be made for certain references in the federal pipeline safety regulations that are incorporated by reference in subsection (16)(A).

1. In 49 CFR 192.909(b, 192.921(a)(4), and 192.937(c)(4), the references to "a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State" should refer to "designated commission personnel" instead.

2. In 49 CFR 192.917(e)(5), the reference to "part 192" should refer to "*[4 CSR 240]***20 CSR 4240**-40.030" instead.

3. In 49 CFR 192.921(a)(2) and 192.937(c)(2), the references to "subpart J of this part" should refer to "*[4 CSR 240]* **20 CSR 4240**-40.030(10)" instead.

4. In 49 CFR 192.933(a)(1) and (2), the references to "a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State" should refer to "designated commission personnel" instead.

5. In 49 CFR 192.935(b)(1)(ii), the reference to "an incident under part 191" should refer to "a federal incident under *[4 CSR 240]* **20 CSR 4240**-40.020" instead.

6. In 49 CFR 192.935(d)(2), the reference to "section 192.705" should refer to "*[4 CSR 240]* **20 CSR 4240**-40.030(13)(C)" instead.

7. In 49 CFR 192.941(b)(2)(i), the reference to "section 192.706" should refer to "*[4 CSR 240]* **20 CSR 4240**-40.030(13)(D)" instead.

8. In 49 CFR 192.945(a), the reference to "section 191.17 of this subchapter" should refer to "*[4 CSR 240]* **20 CSR 4240**-40.020(10)" instead.

9. In 49 CFR 192.947(i), the reference to "a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State" should refer to "designated commission personnel" instead.

10. In 49 CFR 192.951, the reference to "section 191.7 of this subchapter" should refer to "*[4 CSR 240]* **20 CSR 4240**-40.020(5)(A)" instead.

(17) Gas Distribution Pipeline Integrity Management (IM)

(D) What Are the Required Elements of an Integrity Management Plan? (192.1007) A written integrity management plan must contain procedures for developing and implementing the following elements:

1. 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 (e.g., 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.

2. Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operation, and other concerns 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, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

3. 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.

4. 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).

5. 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 paragraph (14)(C)1. (or total number of leaks if all leaks are repaired when found), categorized by cause;

(II) Number of excavation damages;

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

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

(V) Number of hazardous leaks either eliminated or repaired as required by paragraph (14)(C)1. (or total number of leaks if all leaks are repaired when found), categorized by material; and

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

6. Periodic evaluation and improvement. An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one (1) 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 (5) years. The operator must consider the results of the performance monitoring in these evaluations.

7. Report results. Report, on an annual basis, the four (4) measures listed in parts (17)(D)5.A.(I)-(IV), as part of the annual report required by *[4 CSR 240]* **20 CSR 4240**-40.020(7)(A). An operator also must report the four (4) measures to designated commission personnel.

(E) What Must an Operator Report When a Mechanical Fitting Fails? (192.1009)

1. Except as provided in paragraph (17)(E)2., each operator of a distribution pipeline system must submit a report on each mechanical fitting failure, excluding any failure that results only in a nonhazardous leak. The report(s) must be submitted in accordance with *[4 CSR 240]* **20 CSR 4240**-40.020(7)(B) (191.12).

2. The mechanical fitting failure reporting requirements in paragraph (17)(E)1. do not apply to master meter operators.

Appendix A—*[4 CSR 240]* *20 CSR 4240*-40.030
(Reserved)

Appendix B to *[4 CSR 240]* *20 CSR 4240*-40.030
Appendix B—Qualification of Pipe *and Components*

I. List*[ed Pipe]* of Specifications.
A. Listed Pipe Specifications.

ANSI/API Specification 5L—Steel pipe, "API Specification for Line Pipe" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A106/A106M—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in subsection

(1)(D)).

ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A671/A671M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A672/A672M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A691/A691M—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

[ASTM D2513-99, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).]

ASTM D2513-*[09a—Polyethylene thermoplastic pipe and tubing]***12ae1**, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F2817-10 "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

B. Other Listed Specifications for Components.

ASME B16.40-2008 "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM D2513-12ae1"Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1055-98 (2006) "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1924-12 "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1948-12 "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing" (incorporated by reference, in 49 CFR 192.7 and adopted in subsection (1)(D)).

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 in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F2817-10 "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

II. Steel pipe of unknown or unlisted specification.

A. Bending properties. For pipe two inches (2") (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least ninety degrees (90°) around a cylindrical mandrel that has a diameter twelve (12) times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld. For pipe more than two inches (2") (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53/A53M (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), 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 (5) of *[4 CSR 240]* **20 CSR 4240-40.030**. 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 four inches (4") (102 millimeters) in diameter, at least one (1) test weld must be made for each one hundred (100) lengths of pipe. On pipe four inches (4") (102 millimeters) or less in diameter, at least one (1) test weld must be made for each four hundred (400) lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). If 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 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). 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. If the tensile properties of the pipe are not known, the minimum yield strength may be taken as twenty-four thousand (24,000) psi (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 in 49 CFR 192.7 and adopted in subsection (1)(D)). 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.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in paragraph (2)(C)3. of *[4 CSR 240]* **20 CSR 4240-40.030**. (192.55[c])

III. Steel pipe manufactured before November 12, 1970 to earlier editions of listed specifications. Steel pipe manufactured before

November 12, 1970, in accordance with a specification of which a later edition is listed in section I. of this appendix, is qualified for use under this rule if 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; and

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; and

2) Chemical properties of pipe and testing requirements to verify those properties*[.]***; and**

C. Inspection or test of welded pipe. On pipe with welded seams, one (1) 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; or

2) The pipe must be tested in accordance with section (10) of *[4 CSR 240]* **20 CSR 4240-40.030** to at least one and one-fourth (1.25) times the maximum allowable operating pressure if it is to be installed in a Class 1 location and to at least one and one-half (1.5) times the maximum allowable operating pressure if it is to be installed in a Class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under section (10) of *[4 CSR 240]* **20 CSR 4240-40.030**, the test pressure must be maintained for at least eight (8) hours.

Appendix C to *[4 CSR 240]* 20 CSR 4240-40.030
Appendix C—Qualification of Welders for Low Stress Level Pipe

I. Basic test. The test is made on pipe twelve inches (12") (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 (1) 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 (4) coupons and subjected to a root bend test. If, as a result of this test, two (2) or more of the four (4) coupons develop a crack in the weld material, or between the weld material and base metal, that is more than one-eighth inch (1/8") (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 twelve inches (12").

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 if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if 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 (2) samples of the welder's work, each about eight inches (8") (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 two inches (2") (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable; and

2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in paragraph III.1) of this appendix.

Appendix D to 20 CSR 4240-40.030
Appendix D—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) polarized voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made in accordance with sections II. and IV. of this appendix.

2) A minimum negative (cathodic) polarization voltage shift of one hundred (100) millivolts. This polarization voltage shift must be determined in accordance with sections III. and IV. of this appendix.

3) 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.

4) 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 I.B.3) and 4) of this appendix, a minimum negative (cathodic) voltage shift of one hundred fifty (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 I.B.3) and 4) of this appendix, a minimum negative (cathodic) polarization voltage shift of one hundred (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 I.B.1) and 2) of this appendix, aluminum, if cathodically protected at voltages in excess of one and two-tenths (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 buildup of alkalis on the metal surface. A voltage in excess of one and two-tenths (1.20) volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

4) Because aluminum may suffer from corrosion under high pH conditions and because 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 eight (8).

C. Copper structures. A minimum negative (cathodic) polarization voltage shift of one hundred (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. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs I.B.3) and 4) of this appendix, 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 adequately compensated for in order to obtain a valid interpretation of the voltage measurement in paragraphs I.A.1) and I.B.1) of this appendix. Possible methods of compensating for IR drops include:

1) Determining the cathodic voltage immediately upon interruption of the protective current; or

2) If interruption of the protective current is impractical for galvanic systems, the voltage measurements must be obtained at locations where the influence of potential gradients from nearby sacrificial anodes is minimized.

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 I.A.2), I.B.2), and I.C. of this appendix.

IV. Reference half cells.

A. Except as provided in paragraphs IV.B. and IV.C. of this appendix, 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 copper-copper sulfate half cell. Two (2) commonly used reference half cells are listed here 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; and

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 if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

Appendix E to *[4 CSR 240]* 20 CSR 4240-40.030
Appendix E—Table of Contents—Safety Standards—Transportation of Gas by Pipeline.

***[4 CSR 240]* 20 CSR 4240-40.030(1) General**

(A) What Is the Scope of this Rule? (192.1)
(B) Definitions. (192.3)
(C) Class Locations. (192.5)
(D) Incorporation By Reference of the Federal Regulation at 49 CFR 192.7. (192.7)
(E) Gathering Lines. (192.8 and 192.9)
(F) Petroleum Gas Systems. (192.11)
(G) What General Requirements Apply to Pipelines Regulated under this Rule? (192.13)
(H) Conversion to Service Subject to this Rule. (192.14)
(I) Rules of Regulatory Construction. (192.15)
(J) Filing of Required Plans, Procedures, and Programs.
(K) Customer Notification Required by Section 192.16 of 49 CFR 192. (192.16)
(L) Customer Notification, Paragraph (12)(S)2.

***[4 CSR 240]* 20 CSR 4240-40.030(2) Materials**

(A) Scope. (192.51)
(B) General. (192.53)
(C) Steel Pipe. (192.55)
(D) Plastic Pipe. (192.59)
(E) Marking of Materials. (192.63)
(F) Transportation of Pipe. (192.65)
(G) Storage and Handling of Plastic Pipe and Associated Components. (192.67)

***[4 CSR 240]* 20 CSR 4240-40.030(3) Pipe Design**

(A) Scope. (192.101)
(B) General. (192.103)
(C) Design Formula for Steel Pipe. (192.105)
(D) Yield Strength (S) for Steel Pipe. (192.107)
(E) Nominal Wall Thickness (t) for Steel Pipe. (192.109)
(F) Design Factor (F) for Steel Pipe. (192.111)
(G) Longitudinal Joint Factor (E) for Steel Pipe. (192.113)
(H) Temperature Derating Factor (T) for Steel Pipe. (192.115)
(I) Design of Plastic Pipe. (192.121)
(J) *[Design Limitations for Plastic Pipe]* **Reserved.** (192.123)
(K) Design of Copper Pipe for Repairs. (192.125)
(L) Additional Design Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. (192.112)

***[4 CSR 240]* 20 CSR 4240-40.030(4) Design of Pipeline Components**

(A) Scope. (192.141)
(B) General Requirements. (192.143)
(C) Qualifying Metallic Components. (192.144)
(D) Valves. (192.145)
(E) Flanges and Flange Accessories. (192.147)
(F) Standard Fittings. (192.149)
(G) Tapping. (192.151)
(H) Components Fabricated by Welding. (192.153)
(I) Welded Branch Connections. (192.155)
(J) Extruded Outlets. (192.157)
(K) Flexibility. (192.159)
(L) Supports and Anchors. (192.161)
(M) Compressor Stations—Design and Construction. (192.163)
(N) Compressor Stations—Liquid Removal. (192.165)
(O) Compressor Stations—Emergency Shutdown. (192.167)
(P) Compressor Stations—Pressure Limiting Devices. (192.169)
(Q) Compressor Stations—Additional Safety Equipment. (192.171)
(R) Compressor Stations—Ventilation. (192.173)
(S) Pipe-Type and Bottle-Type Holders. (192.175)
(T) Additional Provisions for Bottle-Type Holders. (192.177)
(U) Transmission Line Valves. (192.179)
(V) Distribution Line Valves. (192.181)
(W) Vaults—Structural Design Requirements. (192.183)
(X) Vaults— Accessibility. (192.185)
(Y) Vaults—Sealing, Venting, and Ventilation. (192.187)
(Z) Vaults—Drainage and Waterproofing. (192.189)
(AA) *[Design Pressure of Plastic Fittings. (192.191)]* **Risers Installed After January 22, 2019 (192.204)**
(BB) Valve Installation in Plastic Pipe. (192.193)
(CC) Protection Against Accidental Overpressuring. (192.195)
(DD) Control of the Pressure of Gas Delivered From Transmission Lines and High-Pressure Distribution Systems to Service Equipment. (192.197)
(EE) Requirements for Design of Pressure Relief and Limiting Devices. (192.199)
(FF) Required Capacity of Pressure Relieving and Limiting Stations. (192.201)
(GG) Instrument, Control, and Sampling Pipe and Components. (192.203)
(HH) Passage of Internal Inspection Devices. (192.150)

***[4 CSR 240]* 20 CSR 4240-40.030(5) Welding of Steel in Pipelines**

(A) Scope. (192.221)
(B) General.
(C) Welding Procedures. (192.225)
(D) Qualification of Welders and Welding Operators. (192.227)
(E) Limitations on Welders and Welding Operators. (192.229)
(F) Protection From Weather. (192.231)
(G) Miter Joints. (192.233)

(H) Preparation for Welding. (192.235)
(I) Inspection and Test of Welds. (192.241)
(J) Nondestructive Testing. (192.243)
(K) Repair or Removal of Defects. (192.245)

[4 CSR 240] ***20 CSR 4240*-40.030(6) Joining of Materials Other Than by Welding**
(A) Scope. (192.271)
(B) General. (192.273)
(C) Cast Iron Pipe. (192.275)
(D) Ductile Iron Pipe. (192.277)
(E) Copper Pipe. (192.279)
(F) Plastic Pipe. (192.281)
(G) Plastic Pipe—Qualifying Joining Procedures. (192.283)
(H) Plastic Pipe—Qualifying Persons to Make Joints. (192.285)
(I) Plastic Pipe—Inspection of Joints. (192.287)

[4 CSR 240] ***20 CSR 4240*-40.030(7) General Construction Requirements for Transmission Lines and Mains**
(A) Scope. (192.301)
(B) Compliance With Specifications or Standards. (192.303)
(C) Inspection—General. (192.305)
(D) Inspection of Materials. (192.307)
(E) Repair of Steel Pipe. (192.309)
(F) Repair of Plastic Pipe During Construction. (192.311)
(G) Bends and Elbows. (192.313)
(H) Wrinkle Bends in Steel Pipe. (192.315)
(I) Protection From Hazards. (192.317)
(J) Installation of Pipe in a Ditch. (192.319)
(K) Installation of Plastic Pipe. (192.321)
(L) Casing. (192.323)
(M) Underground Clearance. (192.325)
(N) Cover. (192.327)
(O) Additional Construction Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. (192.328)
(P) Installation of Plastic Pipelines by Trenchless Excavation (192.329)

[4 CSR 240] ***20 CSR 4240*-40.030(8) Customer Meters, Service Regulators, and Service Lines**
(A) Scope, Compliance with Specifications or Standards, and Inspections. (192.351)
(B) Service Lines and Yard Lines.
(C) Customer Meters and Regulators—Location. (192.353)
(D) Customer Meters and Regulators—Protection From Damage. (192.355)
(E) Customer Meters and Regulators— Installation. (192.357)
(F) Customer Meter Installations—Operating Pressure. (192.359)
(G) Service Lines—Installation. (192.361)
(H) Service Lines—Valve Requirements. (192.363)
(I) Service Lines—Location of Valves. (192.365)
(J) Service Lines—General Requirements for Connections to Main Piping. (192.367)
(K) Service Lines—Connections to Cast Iron or Ductile Iron Mains. (192.369)
(L) Service Lines—Steel. (192.371)
(M) Service Lines—Plastic. (192.375)
(N) New Service Lines Not in Use. (192.379)
(O) Service Lines—Excess Flow Valve Performance Standards. (192.381)
(P) Excess Flow Valve Installation. (192.383)
(Q) Manual Service Line Shut-Off Valve Installation (192.385)
(R) Installation of Plastic Service Lines by Trenchless Excavation (192.376)

[4 CSR 240] ***20 CSR 4240*-40.030(9) Requirements for Corrosion Control**
(A) Scope. (192.451)
(B) How Does this Section Apply to Converted Pipelines and Regulated Onshore Gathering Lines? (192.452)
(C) General. (192.453)
(D) External Corrosion Control—Buried or Submerged Pipelines Installed After July 31, 1971. (192.455)
(E) External Corrosion Control—Buried or Submerged Pipelines Installed Before August 1, 1971. (192.457)
(F) External Corrosion Control—Inspection of Buried Pipeline When Exposed. (192.459)
(G) External Corrosion Control—Protective Coating. (192.461)
(H) External Corrosion Control—Cathodic Protection. (192.463)
(I) External Corrosion Control—Monitoring. (192.465)
(J) External Corrosion Control—Electrical Isolation. (192.467)
(K) External Corrosion Control—Test Stations. (192.469)
(L) External Corrosion Control—Test Leads. (192.471)
(M) External Corrosion Control—Interference Currents. (192.473)
(N) Internal Corrosion Control—General and Monitoring. (192.475 and 192.477)
(O) Internal Corrosion Control—Design and Construction of Transmission Line. (192.476)
(P) Atmospheric Corrosion Control—General. (192.479)
(Q) Atmospheric Corrosion Control— Monitoring. (192.481)
(R) Remedial Measures—General. (192.483)
(S) Remedial Measures—Transmission Lines. (192.485)
(T) Remedial Measures—Distribution Lines Other Than Cast Iron or Ductile Iron Lines. (192.487)
(U) Remedial Measures—Cast Iron and Ductile Iron Pipelines. (192.489)
(V) Corrosion Control Records. (192.491)
(W) Direct Assessment. (192.490)

[4 CSR 240] ***20 CSR 4240*-40.030(10) Test Requirements**
(A) Scope. (192.501)
(B) General Requirements. (192.503)
(C) Strength Test Requirements for Steel Pipelines to Operate at a Hoop Stress of Thirty Percent (30%) or More of SMYS. (192.505)
(D) Test Requirements for Pipelines to Operate at a Hoop Stress Less Than Thirty Percent (30%) of SMYS and at or Above One Hundred (100) psi (689 kPa) gauge. (192.507)
(E) Test Requirements for Pipelines to Operate Below One Hundred (100) psi (689 kPa) gauge. (192.509)
(F) Test Requirements for Service Lines. (192.511)
(G) Test Requirements for Plastic Pipelines. (192.513)
(H) Environmental Protection and Safety Requirements. (192.515)
(I) Records. (192.517)
(J) Test Requirements for Customer-Owned Fuel Lines.

[4 CSR 240] ***20 CSR 4240*-40.030(11) Uprating**
(A) Scope. (192.551)
(B) General Requirements. (192.553)
(C) Uprating to a Pressure That Will Produce a Hoop Stress of Thirty Percent (30%) or More of SMYS in Steel Pipelines. (192.555)
(D) Uprating—Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than Thirty Percent (30%) of SMYS—Plastic, Cast Iron, and Ductile Iron Pipelines. (192.557)

[4 CSR 240] ***20 CSR 4240*-40.030(12) Operations**
(A) Scope. (192.601)
(B) General Provisions. (192.603)
(C) Procedural Manual for Operations, Maintenance, and Emergencies. (192.605)
(D) Qualification of Pipeline Personnel (Subpart N).
(E) *Reserved* (192.607)
(F) Change in Class Location—Required Study. (192.609)
(G) Change in Class Location—Confirmation or Revision of Maximum Allowable Operating Pressure. (192.611)
(H) Continuing Surveillance. (192.613)
(I) Damage Prevention Program. (192.614)

(J) Emergency Plans. (192.615)
(K) Public Awareness. (192.616)
(L) Investigation of Failures. (192.617)
(M) Maximum Allowable Operating Pressure—Steel or Plastic Pipelines. (192.619 and 192.620)
(N) Maximum Allowable Operating Pressure—High-Pressure Distribution Systems. (192.621)
(O) Maximum and Minimum Allowable Operating Pressure—Low-Pressure Distribution Systems. (192.623)
(P) Odorization of Gas. (192.625)
(Q) Tapping Pipelines Under Pressure. (192.627)
(R) Purging of Pipelines. (192.629)
(S) Providing Service to Customers.
(T) Control Room Management. (192.631)

[4 CSR 240] ***20 CSR 4240*****-40.030(13) Maintenance**
(A) Scope. (192.701)
(B) General. (192.703)
(C) Transmission Lines—Patrolling. (192.705)
(D) Transmission Lines—Leakage Surveys. (192.706)
(E) Line Markers for Mains and Transmission Lines. (192.707)
(F) Record Keeping.
(G) Transmission Lines—General Requirements for Repair Procedures. (192.711)
(H) Transmission Lines—Permanent Field Repair of Imperfections and Damages. (192.713)
(I) Transmission Lines—Permanent Field Repair of Welds. (192.715)
(J) Transmission Lines— Permanent Field Repair of Leaks. (192.717)
(K) Transmission Lines—Testing of Repairs. (192.719)
(L) Distribution Systems—Patrolling. (192.721)
(M) Distribution Systems—Leakage Surveys. (192.723)
(N) Test Requirements for Reinstating Service Lines and Fuel Lines. (192.725)
(O) Abandonment or Deactivation of Facilities. (192.727)
(P) Compressor Stations—Inspection and Testing of Relief Devices. (192.731)
(Q) Compressor Stations—Storage of Combustible Materials and Gas Detection. (192.735 and 192.736)
(R) Pressure Limiting and Regulating Stations—Inspection and Testing. (192.739)
(S) Pressure Limiting and Regulating Stations—Telemetering or Recording Gauges. (192.741)
(T) Pressure Limiting and Regulating Stations—Capacity of Relief Devices. (192.743)
(U) Valve Maintenance—Transmission Lines. (192.745)
(V) Valve Maintenance—Distribution Systems. (192.747)
(W) Vault Maintenance. (192.749)
(X) Prevention of Accidental Ignition. (192.751)
(Y) Caulked Bell and Spigot Joints. (192.753)
(Z) Protecting or Replacing Disturbed Cast Iron Pipelines. (192.755)
(AA) Repair of Plastic Pipe. **(192.720)**
(BB) Pressure Regulating, Limiting, and Overpressure Protection—Individual Service Lines Directly Connected to Production, Gathering, or Transmission Pipelines. (192.740)
(CC) Joining Plastic Pipe by Heat Fusion; Equipment Maintenance and Calibration. (192.756)

[4 CSR 240] ***20 CSR 4240*****-40.030(14) Gas Leaks**
(A) Scope.
(B) Investigation and Classification Procedures.
(C) Leak Classifications.

[4 CSR 240] ***20 CSR 4240*****-40.030(15) Replacement Programs**
(A) Scope.
(B) Replacement Programs—General Requirements.
(C) Replacement Program—Unprotected Steel Service Lines and Yard Lines.
(D) Replacement Program—Cast Iron.
(E) Replacement/Cathodic Protection Program—Unprotected Steel Transmission Lines, Feeder Lines, and Mains.

[4 CSR 240] ***20 CSR 4240*****-40.030(16) Pipeline Integrity Management for Transmission Lines.**

[4 CSR 240] ***20 CSR 4240*****-40.030(17) Gas Distribution Pipeline Integrity Management (IM)**
(A) What Definitions Apply to this Section? (192.1001)
(B) What Do the Regulations in this Section Cover? (192.1003)
(C) What Must a Gas Distribution Operator (Other than a Master Meter Operator) Do to Implement this Section? (192.1005)
(D) What Are the Required Elements of an Integrity Management Plan? (192.1007)
(E) What Must an Operator Report When a Mechanical Fitting Fails? (192.1009)
(F) What Records Must an Operator Keep? (192.1011)
(G) When May an Operator Deviate from Required Periodic Inspections Under this Rule? (192.1013)
(H) What Must a Master Meter Operator Do to Implement this Section? (192.1015)

[4 CSR 240] **20 CSR 4240-40.030(18) Waivers of Compliance.**

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. Original rule filed Feb. 23, 1968, effective March 14, 1968. For intervening history, please consult the ***Code of State Regulations****. Amended: Filed Dec 12, 2019.*

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions in excess of five hundred dollars ($500) in total.

PRIVATE COST: This proposed amendment will not cost private entities in excess of five hundred dollars ($500) in total.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file a statement in support of or in opposition to the proposed amendment with the Missouri Public Service Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received no later than February 14, 2020, and should include a reference to Commission Case No. GX-2020-0112. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/efis.asp. A public hearing is scheduled for 10:00 a.m., February 24, 2020, in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment, and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

Title 20—DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

PROPOSED AMENDMENT

20 CSR 4240-40.033 Safety Standards-Liquefied Natural Gas Facilities. The commission is amending the Purpose and sections (1) and (3) of this rule.

PURPOSE: This rule prescribes safety standards for liquefied natural gas (LNG) facilities used in the transportation of gas by pipeline that is subject to the pipeline safety standards in [4 CSR 240] 20 CSR 4240-40.030. This rule adopts the federal regulations on this subject matter that apply to operators of liquefied natural gas facilities used in the transportation of gas by pipeline that is subject to the federal pipeline safety laws and pipeline safety standards.

PURPOSE: This amendment proposes to amend the rule to adopt the most recent publication of 49 CFR part 193 and update references to CSR.

(1) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 201*[7]*8, 49 CFR part 193 is incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR part 193. The *Code of Federal Regulations* is published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 201*[7]*8 version of 49 CFR part 193 is available at www.gpo.gov/fdsys/search/showcitation.action.

(3) For purposes of this rule, the following substitutions should be made for certain references in the federal pipeline safety regulations adopted by reference in section (2) of this rule:

(C) The reference in 49 CFR 193.2011 to "Part 191 of this subchapter" for reporting of incidents, safety-related conditions, and annual pipeline summary data for LNG plants or facilities should refer to *[4 CSR 240]* **20 CSR 4240**-40.020 instead;

(D) The reference in 49 CFR 193.2605 to "Part 191.23 of this subchapter" for reporting requirements for safety related conditions should refer to *[4 CSR 240]* **20 CSR 4240**-40.020(12) instead;

(E) The reference in 49 CFR 193.2001 to "Part 192 of this chapter" for applicability of the standards should refer to *[4 CSR 240]* **20 CSR 4240**-40.030 instead;

(F) The reference in 49 CFR 193.2629 to "section 192.461 of this chapter" for protective coatings should refer to *[4 CSR 240]* **20 CSR 4240**-40.030(9)(G)*["]* instead; and

(G) The references in 49 CFR 193.2629 and 193.2635 to "section 192.463 of this chapter" for cathodic protection should refer to *[4 CSR 240]* **20 CSR 4240**-40.030(9)(H) instead.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.033. Emergency rule filed Dec. 19, 2018, effective Dec. 29, 2018, expired June 26, 2019. Original rule filed Dec. 20, 2018, effective July 30, 2019. Moved to 20 CSR 4240-40.033, effective Aug. 28, 2019. Amended: Filed Dec. 12, 2019.

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions in excess of five hundred dollars ($500) in total.

PRIVATE COST: This proposed amendment will not cost private entities in excess of five hundred dollars ($500) in total.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file a statement in support of or in opposition to the proposed amendment with the Missouri Public Service Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received no later than February 14, 2020, and should include a reference to Commission Case No. GX-2020-0112. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/efis.asp. A public hearing is scheduled for 10:00 a.m., February 24, 2020, in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment, and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

Title 20—DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

PROPOSED AMENDMENT

20 CSR 4240-40.080 Drug and Alcohol Testing. The commission is amending sections (1) and (4) of this rule.

PURPOSE: This amendment proposes to amend the rule to adopt additional portions of 49 CFR part 199 and update references to CSR.

(1) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 201*[7]*8, **and the subsequent amendment published on April 23, 2019 (published in *Federal Register* on April 23, 2019, page 84 FR 16770),** 49 CFR parts 40 and 199 are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR parts 40 and 199. The *Code of Federal Regulations* is published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 201*[7]*8, version of 49 CFR parts 40 and 199 *[is available at www.gpo.gov/fdsys/search/showcitation.action]* **and the *Federal Register* publication on page 84 FR 16770 are available at https://www.govinfo.gov/#citation.**

(4) For purposes of this rule, the following substitutions should be made for certain references in the federal pipeline safety regulations adopted by reference in section (2) of this rule:

(B) The references to "accident" in sections 199.3, 199.100, 199.105, 199.200, 199.221, 199.225, 199.227, and 199.231 of 49 CFR part 199 should refer to a "federal incident reportable under *[4 CSR 240]* **20 CSR 4240**-40.020" instead;

(C) The references to "part 192, 193, or 195 of this chapter" or "part 192, 193, or 195" in sections 199.1, 199.3, 199.100, and 199.200 of 49 CFR part 199 should refer to "*[4 CSR 240]* **20 CSR 4240**-40.030 **or 40.033**" instead (the commission regulations contained in *[4 CSR 240]* **20 CSR 4240**-40.030 parallel 49 CFR part 192, **and 20 CSR 4240-40.033 adopts 49 CFR part 193,** but the commission does not have any rules pertaining to 49 CFR part *[193 or]*195); and

(D) The references to the applicability exemptions for operators of master meter systems as defined in section "191.3 of this chapter" in 49 CFR 199.2 should refer to "*[4 CSR 240]* **20 CSR 4240**-40.020(2)(G)" instead.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.080. Original rule filed Nov. 29, 1989, effective April 2, 1990. For intervening history, please consult the **Code of State Regulations**. *Amended: Filed Dec. 12, 2019.*

PUBLIC COST: This proposed amendment will not cost state agencies *or political subdivisions in excess of five hundred dollars ($500) in total.*

PRIVATE COST: This proposed amendment will not cost private entities in excess of five hundred dollars ($500) in total.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file a statement in support of or in opposition to the proposed amendment with the Missouri Public Service Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received no later than February 14, 2020, and should include a reference to Commission Case No. GX-2020-0112. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/efis.asp. A public hearing is scheduled for 10:00 a.m., February 24, 2020, in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment, and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.