Title 4 – Department of Economic Development
Division 240 – Public Service Commission
Chapter 40 – Gas Utilities and Gas Safety Standards

PROPOSED AMENDMENT

4 CSR 240-40.030 Safety Standards – Transportation of Gas by Pipeline. The Commission is amending sections (1), (2), (3), (4), (6), (8), (9), (12), (13), (16); adding a new section (17); amending renumbered section (18); and amending Appendix E.

PURPOSE: This amendment proposes to amend the rule to address amendments of 49 CFR part 192 promulgated between October 2007 and May 2012, to clarify the rule, and to make editorial changes.

(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;

~~2~~**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;

~~3~~**4**. Building means any structure that is regularly or periodically occupied by people;

~~4~~**5**. Commission means the Missouri Public Service Commission;

~~5~~**6**. Customer meter means the meter that measures the transfer of gas from an operator to a consumer;

~~6~~**7**. Designated commission personnel means the pipeline safety program manager at the address contained in 4 CSR 240-40.020(5)**(E)** for required correspondence;

~~7~~**8**. Distribution line means a pipeline other than a gathering or transmission line;

9. 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;

~~8~~**10**. 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);

~~9~~**11**. 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;

~~10~~**12**. Fuel line means the customer-owned gas piping downstream from the outlet of the customer meter or operator-owned pipeline, whichever is farther downstream;

~~11~~**13**. Gas means natural gas, flammable gas, manufactured gas, or gas which is toxic or corrosive;

~~12~~**14**. Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main;

~~13~~**15**. 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;

~~14~~**16**. 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;

~~15~~**17**. Listed specification means a specification listed in subsection I. of Appendix B, which is included herein (at the end of this rule);

~~16~~**18**. 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;

~~17~~**19**. Main means a distribution line that serves as a common source of supply for more than one (1) service line;

~~18~~**20**. Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of one (1) year;

~~19~~**21**. Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this rule;

~~20~~**22**. Municipality means a city, village or town;

~~21~~**23**. Operator means a person who engages in the transportation of gas;

~~22~~**24**. 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;

~~23~~**25**. 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) *[guage]* **gauge** at 100°F (38°C);

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

~~24~~**27**. Pipe means any pipe or tubing used in the transportation of gas, including pipe-type holders;

~~25~~**28**. 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;

29. 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;

~~26~~**30**. Pipeline facility means new and existing ~~pipeline~~**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;

~~27~~**31**. Reading means the highest sustained reading when testing in a bar hole or opening without induced ventilation;

~~28~~**32**. 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;

~~29~~**33**. 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;

~~30~~**34**. 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]);

~~31~~**35**. Sustained reading means the reading taken on a combustible gas indicator unit after adequately venting the test hole or opening;

~~32~~**36**. 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;

~~33~~**37**. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas in Missouri;

~~34~~**38**. Tunnel means a subsurface passageway large enough for a man to enter;

~~35~~**39**. Vault or manhole means a subsurface structure that a man can enter; and

~~36~~**40**. 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 shall mean 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 shall 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 shall 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, ~~2006~~**2011**, ~~*and the subsequent amendment 192-103 (published in Federal Register on February 1, 2007, page 72 FR 4655),*~~ 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, ~~2006~~ **2011** version of 49 CFR part 192 is available at ~~*www.access.gpo.gov/nara/cfr/cfr-table-search.html*~~ **www.gpo.gov/fdsys/search/showcitation.action**. ~~*The Federal Register publication on page 72 FR 4655 is available at www.gpoaccess.gov/fr/advanced.html.*~~

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 in the ~~*U.S. Department of Transportation—*~~ **Office of Pipeline Safety,** Pipeline and Hazardous Materials Safety Administration, ~~*400 7th St. SW*~~**1200 New Jersey Avenue SE**, Washington, DC**20590-0001**, or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030 or 866-272-6272. In addition, the incorporated materials are available from the respective 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 ~~2007~~ **2008** amendment of this rule. As of the ~~2007~~ **2008** amendment, Appendix A to this rule is also "Reserved" and included herein.

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

(E) Marking of Materials. (192.63)

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

A. As prescribed in the specification or standard to which it was manufactured; however, thermoplastic fittings must be marked in accordance with ASTM D 2513**-87 (incorporated by reference in 49 CFR 192.7 and adopted in (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.

(F) Transportation of Pipe. (192.65)

1. Railroad. In a pipeline to be operated at a hoop stress of twenty percent (20%) or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of seventy to one (70:1) or more that is transported by railroad unless —

~~1~~**A**. The transportation is performed in accordance with API ~~RP5L1~~**Recommended Practice 5L1 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**; and

~~2~~**B**. In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with section (10) 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 ½~~**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), the test pressure must be maintained for at least eight (8) hours.

2. Ship or barge. In a pipeline to be operated at a hoop stress of twenty percent (20%) or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of seventy to one (70:1) or more that is transported by ship or barge on both inland and marine waterways unless the

transportation is performed in accordance with API Recommended Practice 5LW (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)).

(3) Pipe Design.

(I) Design of Plastic Pipe. (192.121) Subject to the limitations of subsection (3)(J), the design pressure for plastic pipe is determined in accordance with either of the following formulas:

$$P = 2S \frac{t}{(D-t)} \times 0.32$$

$$P = \frac{2S}{(SDR-1)} \times 0.32$$

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–3/2004*~~**PPI TR–3/2008**, HDB/PDB/SDB/MRS Policies (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D));

t = Specified wall thickness, in (mm);

D = Specified outside diameter, in (mm); 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.

(J) Design Limitations for Plastic Pipe. (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 ~~*following applicable temperatures for thermoplastic pipe, 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

(D) Valves. (192.145)

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

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~~; and~~

~~*C. No valve having pressure containing parts made of ductile iron may be used in the gas pipe components of compressor stations*~~.

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.

(AA) Design Pressure of Plastic Fittings. (192.191) Thermoplastic fittings for plastic pipe must conform to ASTM D 2513**-99 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**.

(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 ~~*Designation*~~ D2513**-99 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**; and

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

3. Heat-fusion joints. Each heat-fusion joint on plastic pipe must comply with 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, compresses the heated ends together and holds the pipe in proper alignment while the plastic hardens;

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

C. An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of (6)(G)1.A.(III), to be at least equivalent to those of the fittings manufacturer; and

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

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

~~*A. The adhesive must conform to ASTM Designation D2517; and*~~

~~*B. The materials and adhesive must be compatible with each other.*~~ ***(Reserved)***

5. 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.

(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:

A. The burst test requirements of—

(I) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2513**-99** (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D));

(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 Designation F1055 (incorporated by reference in 49 CFR 192.7 and adopted in (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 (1)(D)), except that the test may be conducted at ambient temperature and humidity. If the 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:

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 (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.

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

(P) Excess Flow Valve ~~*Customer Notification*~~ **Installation**. (192.383)

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

~~*A. Costs associated with installation means the costs directly connected with installing an excess flow valve, for example, costs of parts, labor, inventory and procurement. It does not include maintenance and replacement costs until such costs are incurred.*~~

~~*B*~~**A**. Replaced service line means a ~~*natural*~~ 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 customer means the person who pays the gas bill, or where service has not yet been established, the person requesting service.*~~

B. Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence.

~~*2. Which customers must receive notification. Notification is required on each newly installed service line or replaced service line that operates continuously throughout the year at a pressure not less than ten (10) psi (69 kPa) gauge and that serves a single residence. On these lines an operator of a natural gas distribution system must notify the service line customer once in writing.*~~

~~*3. What to put in the written notice.*~~

~~*A. An explanation for the customer that an excess flow valve (EFV) meeting the performance standards prescribed under subsection (8)(O) is available for the operator to install if the customer bears the costs associated with installation;*~~

~~*B. An explanation for the customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include that an EFV is designed to shut off flow of natural gas automatically if the service line breaks; and*~~

~~*C. A description of installation, maintenance, and replacement costs. The notice must explain that if the customer requests the operator to install an EFV, the customer bears all costs associated with installation, and what those costs are. The notice must alert the customer that costs*~~

~~*for maintaining and replacing an EFV may later be incurred, and what those costs will be, to the extent known.*~~

~~*4. When notification and installation must be made.*~~

~~*A. After February 3, 1999, an operator must notify each service line customer set forth in paragraph (8)(P)2.:*~~

~~*(I) On new service lines when the customer applies for service; and*~~

~~*(II) On replaced service lines when the operator determines the service line will be replaced.*~~

~~*B. If a service line customer requests installation, an operator must install the EFV at a mutually agreeable date.*~~

~~*5. What records are required.*~~

~~*A. An operator must make the following records available for inspection by designated commission personnel:*~~

~~*(I) A copy of the notice currently in use; and*~~

~~*(II) Evidence that notice has been sent to the service line customers set forth in paragraph (8)(P)2., within the previous three years.*~~

~~*B. (Reserved)*~~

~~*6. When notification is not required. The notification requirements do not apply if the operator can demonstrate—*~~

~~*A. That the operator will voluntarily install an excess flow valve or that the state or local jurisdiction requires installation;*~~

~~*B. That excess flow valves meeting the performance standards in subsection (8)(O) are not available to the operator;*~~

~~*C. That the operator has prior experience with contaminants in the gas stream that could interfere with the operation of an excess flow valve, cause loss of service to a residence, or interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or*~~

~~*D. That an emergency or short time notice replacement situation made it impractical for the operator to notify a service line customer before replacing a service line. Examples of these situations would be where an operator has to replace a service line quickly because of—*~~

~~*(I) Third party excavation damage;*~~

~~*(II) Class 1 leaks as defined in the paragraph (14)(C)1.; or*~~

~~*(III) A short notice service line relocation request.*~~

2. Installation required. An excess flow valve (EFV) installation must comply with the performance standards in subsection (8)(O). The operator must install an EFV on any new or replaced service line serving a single-family residence after February 12, 2010, unless one or more of the following conditions is 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.

3. Reporting. Each operator must report the EFV measures detailed in the annual report required by 4 CSR 240-40.020(7)(A).

(9) Requirements for Corrosion Control.

(I) External Corrosion Control—Monitoring. (192.465)

1. Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding fifteen (15) months, to determine whether the cathodic protection meets the requirements of subsection (9)(H). (192.463) However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of one hundred feet (100') (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least twenty percent (20%) of these protected structures, distributed over the entire system, must be surveyed each calendar year, with a different twenty percent (20%) checked each subsequent year, so that the entire system is tested in each five (5)-year period. Each short section of metallic pipe less than one hundred feet (100') (30 meters) in length installed and cathodically protected in accordance with paragraph (9)(R)2. (192.483[b]), each segment of pipe cathodically protected in accordance with paragraph (9)(R)3. (192.483[c]) and each electrically isolated metallic fitting not meeting the requirements of paragraph (9)(D)5. (192.455[f]) must be monitored at a minimum rate of ten percent (10%) each calendar year, with a different ten percent (10%) checked each subsequent year, so that the entire system is tested every ten (10) years.

2. Each cathodic protection rectifier or other impressed current power source must be inspected six (6) times each calendar year but with intervals not exceeding two and one-half (2 1/2) months to ensure that it is operating.

3. Each reverse current switch, each diode and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six (6) times each calendar year, but with intervals not exceeding two and one-half (2 1/2) months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding fifteen (15) months.

4. Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring required in paragraphs (9)(I)1.–3. Corrective measures must be completed within six (6) months unless otherwise approved by designated commission personnel.

5. After the initial evaluation required by paragraphs (9)(D)2. and (9)(E)2., each operator must, not less than every three (3) years at intervals not exceeding thirty-nine (39) months, reevaluate its unprotected pipelines and cathodically protect them in accordance with section (9) in areas in which active corrosion is found, except that unprotected steel service lines must be replaced as required by subsection (15)(C). The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, the pipeline environment, and by instrument leak detection surveys (see subsections (13)(D) and (13)(M)). When the operator conducts electrical surveys, the operator must demonstrate that the surveys effectively identify areas of active corrosion. ~~*In this subsection and subsection (9)(E):*~~

~~*A. Active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety;*~~

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

~~*C. 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.*~~

(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. The manual must be revised, as necessary, within one (1) year of the effective date of revisions to this rule. 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 240-40.020 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)**; ~~and~~

N. Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under (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.

(J) Emergency Plans. (192.615)

1. Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

A. Receiving, identifying and classifying notices of events which require immediate response by the operator;

B. Establishing and maintaining adequate means of communication with appropriate fire, police and other public officials;

C. Responding promptly and effectively to a notice of each type of emergency, including the following:

(I) Gas detected inside or near a building;

(II) Fire located near or directly involving a pipeline facility;

(III) Explosion occurring near or directly involving a pipeline facility; and

(IV) Natural disaster;

D. Making available personnel, equipment, tools and materials, as needed at the scene of an emergency;

E. Taking actions directed toward protecting people first and then property;

F. Causing an emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property;

G. Making safe any actual or potential hazard to life or property;

H. Notifying appropriate fire, police and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency;

I. Safely restoring any service outage; ~~and~~

J. Beginning action under subsection (12)(L) (192.617), if applicable, as soon after the end of the emergency as possible~~.~~**; and**

K. Actions required to be taken by a controller during an emergency in accordance with subsection (12)(T).

2. Each operator shall—

A. Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (12)(J)1. as necessary for compliance with those procedures;

B. Train the appropriate operating personnel and conduct an annual review to assure that they are knowledgeable of the emergency procedures and verify that the training is effective; and

C. Review employee activities to determine whether the procedures were effectively followed in each emergency.

3. Each operator shall establish and maintain liaison with appropriate fire, police and other public officials to—

A. Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

B. Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

C. Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

D. Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

(K) Public Awareness. (192.616)

1. **Except for an operator of a master meter system covered under paragraph (12)(K)10., ~~E~~e**ach pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)). In addition, the program must provide for notification of the intended groups on the following schedule:

A. Appropriate government organizations and persons engaged in excavation related activities must be notified at least annually;

B. The public must be notified at least semiannually; and

C. Customers must be notified at least semiannually by mailings or hand-delivered messages and at least nine (9) times a calendar year by billing messages.

2. The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.

3. The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

4. The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

A. Use of a one-call notification system prior to excavation and other damage prevention activities;

B. Possible hazards associated with unintended releases from a gas pipeline facility;

C. Physical indications that such a release may have occurred;

D. Steps that should be taken for public safety in the event of a gas pipeline release; and

E. Procedures for reporting such an event.

5. The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

6. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.

7. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

8. Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. ~~*As an exception, master meter operators having less than twenty five (25) customers must have completed development and documentation of their programs no later than June 20, 2007.*~~ **The operator of a master meter covered under paragraph (12)(K)10. must complete development of its written procedure by June 13, 2008.** Operators must submit their completed programs and any program changes to designated commission personnel as required by subsection (1)(J).

9. The operator's program documentation and evaluation results must be available for periodic review by designated commission personnel.

10. Unless the operator transports gas as a primary activity, the operator of a master meter is not required to develop a public awareness program as prescribed in paragraphs (12)(K)1.-7. Instead the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:

A. A description of the purpose and reliability of the pipeline;

B. An overview of the hazards of the pipeline and prevention measures used;

C. Information about damage prevention;

D. How to recognize and respond to a leak; and

E. How to get additional information.

(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 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 (1)(D)), reduced by the appropriate factor in (12)(M)1.B.(II); or

(II) If the pipe is twelve and three-quarter inches (12¾") (324 mm) or less in outside diameter and is not tested to yield under this paragraph, two hundred (200) psi (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 (689 kPa) gauge or more, the test pressure is divided by a factor determined in accordance with the following table:

	Factors[1], segment -		
Class 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

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 (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 (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 (12)(M)1.C. An operator must still comply with (12)(G).

4. 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 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 (12)(T)2., (12)(T)3.E., (12)(T)4.B. and C., (12)(T)6. and (12)(T)7. must be implemented no later than October 1, 2011. The procedures required by (12)(T)3.A.-D., (12)(T)4.A. and D., and (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; and

D. A method of recording controller shift-changes and any hand-over of responsibility between controllers.

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 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 240-40.020 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.

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; and

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.

9. *Compliance validation.* Operators must submit their procedures to designated commission personnel as required by 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.

(G) Transmission Lines — General Requirements for Repair Procedures. (192.711)

1. **Temporary Repairs.** Each operator ~~shall~~ **must** take immediate temporary measures to protect the public whenever —

A. A leak, imperfection or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above forty percent (40%) of the SMYS; and

B. It is not feasible to make a permanent repair at the time of discovery. ~~As soon as feasible the operator shall make permanent repairs.~~

2. Permanent repairs. An operator must make permanent repairs on its pipeline system according to the following:

A. Non integrity management repairs: The operator must make permanent repairs as soon as feasible.

B. Integrity management repairs: When an operator discovers a condition on a pipeline covered under section (16) – Pipeline Integrity Management for Transmission Lines (Subpart O), the operator must remediate the condition as prescribed by 49 CFR 192.933(d) (this federal regulation is incorporated by reference and adopted in section (16)).

~~2~~**3. Welded patch.** Except as provided in subparagraph (13)(J)2.C. (192.717[b][3]), no operator may use a welded patch as a means of repair.

(O) Abandonment or Deactivation of Facilities. (192.727)

1. Each operator shall perform abandonment or deactivation of pipelines in accordance with the requirements of this subsection.

2. Each pipeline abandoned in place must be disconnected from all sources and supplies of gas, purged of gas and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

3. Except for service lines, each inactive pipeline that is not being maintained under this rule must be disconnected from all sources and supplies of gas, purged of gas and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

4. Whenever service to a customer is discontinued, one (1) of the following must be complied with:

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

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

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

5. If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging.

6. Each abandoned vault must be filled with a suitable compacted material.

7. For each abandoned pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility. The addresses (mail and e-mail) and phone numbers given in this paragraph are from 49 CFR 192.727(g) as published on

October 1, ~~2006~~**2009**. Please consult the current edition of 49 CFR part 192 for any updates to these addresses and phone numbers.

A The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS ``Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at www.npms.phmsa.dot.gov or contact the NPMS National Repository at 703-317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the ~~*Information Officer*~~**Office of Pipeline Safety**, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, ~~*Room 2103, 400 Seventh Street, SW*~~ **Information Resources Manager, PHP-10, 1200 New Jersey Avenue SE**, Washington DC 20590**-0001**; fax (202) 366-4566; e-mail, ~~*roger.little@dot.gov*~~***InformationResourcesManager@phmsa.dot.gov***. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

B. *(Reserved)*

(R) Pressure Limiting and Regulating Stations – Inspection and Testing. (192.739)

1. Each pressure limiting station, relief device (except rupture discs) and pressure regulating station and its equipment must be subjected at intervals not exceeding fifteen (15) months but at least once each calendar year to inspections and tests to determine that it is —

A. In good mechanical condition;

B. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

C. Except as provided in paragraph (13)(R)2., set to control or relieve at the correct pressures that will prevent downstream pressures from exceeding the allowable pressures under subsections (4)(FF), and (12)(M)–(O);

D. Properly installed and protected from dirt, liquids and other conditions that might prevent proper operation;

E. Properly protected from unauthorized operation of valves in accordance with paragraph (4)(EE)8.;

F. Equipped to indicate regulator malfunctions in accordance with paragraphs (4)(EE)10. and 11. in a manner that is adequate from the standpoint of reliability of operation; and

G. Equipped with adequate over-pressure protection in accordance with paragraph (4)(EE)9.

2. For steel pipelines whose MAOP is determined under paragraph (12)(M)3., if the MAOP is sixty (60) psi (414 kPa) ~~*guage*~~ **gauge** or more, the control or relief pressure limit is as follows:

A. If the MAOP produces a hoop stress that is greater than seventy-two percent (72%) of SMYS, then the pressure limit is MAOP plus four percent (4%).

B. If the MAOP produces a hoop stress that is unknown as a percentage of SMYS, then the pressure limit is a pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

(16) Pipeline Integrity Management for Transmission Lines.

(A) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, ~~*2006*~~**2011**~~*, the subsequent amendment 192-103 (published in Federal Register on February 1, 2007, page 72 FR 4655), and the subsequent amendment published on July 17, 2007 (published in Federal Register on July 17, 2007, page 72 FR 39012*~~, 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, ~~*2006*~~**2011** version of 49 CFR part 192 is available at ~~*www.access.gpo.gov/nara/cfr/cfr-table-search.html*~~**www.gpo.gov/fdsys/search/showcitation.action**.~~*The Federal Register publications on page 72 FR 4655 and page 72 FR 39012 are available at www.gpoaccess.gov/fr/advanced.html.*~~

(C) Subpart O and appendix E to 49 CFR part 192 contain the federal regulations regarding pipeline integrity management for transmission lines. Subpart O includes sections 192.901 through 192.951. Information regarding subpart O is available at http://primis.phmsa.dot.gov/gasimp.

(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 240-40.020(5)(A) for reports to PHMSA.

(E) In 49 CFR 192.911(m) and (n), the references to "A State or local pipeline safety authority when the covered segment is located in a State where OPS has an interstate agent agreement" do not apply to Missouri and are replaced with "designated commission personnel". As a result, the communication plan required by 49 CFR 192.911(m) must include procedures for addressing safety concerns raised by designated commission personnel and the procedures required by 49 CFR 192.911(n) must address providing a copy of the operator's risk analysis or integrity management program to designated commission personnel.

(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 240-40.030" 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 240-40.030(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 240-40.020" instead.

6. In 49 CFR 192.935(d)(2), the reference to "§192.705" should refer to "4 CSR 240-40.030(13)(C)" instead.

7. In 49 CFR 192.941(b)(2)(i), the reference to "§192.706" should refer to "4 CSR 240-40.030(13)(D)" instead.

8. In 49 CFR 192.945(a), the reference to "§191.17 of this subchapter" should refer to "4 CSR 240-40.020(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 "§191.7 of this subchapter" should refer to "4 CSR 240-40.020(5)(A)" instead.

(17) Gas Distribution Pipeline Integrity Management (IM)

(A) What Definitions Apply to this Section? (192.1001) The following definitions apply to this section.

1. Excavation damage means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

2. Hazardous leak means a Class 1 leak as defined in paragraph (14)(C)1.

3. Integrity management plan or IM plan means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this section.

4. Integrity management program or IM program means an overall approach by an operator to ensure the integrity of its gas distribution system.

5. Mechanical fitting means a mechanical device used to connect sections of pipe. The term ''Mechanical fitting'' applies only to:

A. Stab Type fittings;

B. Nut Follower Type fittings;

C. Bolted Type fittings; or

D. Other Compression Type fittings.

(B) What Do the Regulations in this Section Cover? (192.1003) This section prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this rule. A gas distribution operator, other than a master meter operator, must follow the requirements in subsections (17)(C)-(G). A master meter operator of a gas distribution line must follow the requirements in subsection (17)(H). Information about IM programs is available at http://primis.phmsa.dot.gov/dimp.

(C) What Must a Gas Distribution Operator (Other than a Master Meter Operator) Do to Implement this Section? (191.1005) No later than August 2, 2011, a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in subsection (17)(D).

(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 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 measures listed in (17)(D)5.A.(I)-(IV), as part of the annual report required by 4 CSR 240-40.020(7)(A). An operator also must report the four 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 240-40.020(7)(B) (191.12).

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

(F) What Records Must an Operator Keep? (192.1011) An operator must maintain records demonstrating compliance with the requirements of this section for at least ten (10) years. The records must include copies of superseded integrity management plans developed under this section.

(G) When May an Operator Deviate from Required Periodic Inspections Under this Rule? (192.1013)

1. An operator may propose to reduce the frequency of periodic inspections and tests required in this rule on the basis of the engineering analysis and risk assessment required by this section.

2. An operator must submit its written proposal to the secretary of the commission. The commission may accept the proposal on its own authority, with or without conditions and limitations as the commission deems appropriate, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

3. An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

(H) What Must a Master Meter Operator Do to Implement this Section? (192.1015)

1. General. No later than August 2, 2011, the operator of a master meter system must develop and implement an IM program that includes a written IM plan as specified in paragraph (17)(G)2. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

2. Elements. A written integrity management plan must address, at a minimum, the following elements:

A. *Knowledge.* The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (e.g., design, construction, operations or maintenance activities).

B. *Identify threats.* The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.

C. *Rank risks.* The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.

D. *Identify and implement measures to mitigate risks.* The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.

E. *Measure performance, monitor results, and evaluate effectiveness.* The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.

F. *Periodic evaluation and improvement.* The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

3. Records. The operator must maintain, for a period of at least ten (10) years, the following records:

A. A written IM plan in accordance with this subsection, including superseded IM plans;

B. Documents supporting threat identification; and

C. Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

~~(17)~~ **(18)** Waivers of Compliance. Upon written request to the secretary of the commission, the commission, by authority order and under such terms and conditions as the commission deems appropriate, may waive in whole or part compliance with any of the requirements contained in this rule. Waivers will be granted only on a showing that gas safety is not compromised. If the waiver request would waive compliance with a federal requirement in 49 CFR part 192, additional actions shall be taken in accordance with 49 USC 60118 **except when the provisions of subsection (17)(G) apply**.

Appendix B to 4 CSR 240-40.030
Appendix B – Qualification of Pipe

I. Listed Pipe Specifications.

API 5L—Steel pipe, "API Specification for Line Pipe" (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)).
ASTM A 53/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 (1)(D)).
ASTM A 106—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)).
ASTM A 333/A 333M—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 (1)(D)).
ASTM A 381—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 (1)(D)).
ASTM A 671—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 (1)(D)).
ASTM A 672—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 (1)(D)).

ASTM A 691—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 (1)(D)).

ASTM D 2513**-99** — Thermoplastic pipe and tubing, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)).

Appendix E to 4 CSR 240-40.030

Appendix E. Table of Contents - Safety Standards - Transportation of Gas by Pipeline.

4 CSR 240-40.030(8) Customer Meters, Service Regulators, and Service Lines

(P) Excess Flow Valve ~~*Customer Notification*~~**Installation**. (192.383)

4 CSR 240-40.030(12) Operations

(T) Control Room Management. (192.631)

4 CSR 240-40.030(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? (191.1005)

(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 240-40.030~~*(17)*~~**(18)** Waivers of Compliance.

AUTHORITY: sections 386.250 and 386.310 and 393.140, RSMo 2000. Original rule filed Feb. 23, 1968, effective March 14, 1968. Amended: Filed Dec. 28, 1970, effective Jan. 6, 1971. Amended: Filed Dec. 29, 1971, effective Jan. 7, 1972. Amended: Filed Feb. 16, 1973, effective Feb. 26, 1973. Amended: Filed Feb. 1, 1974, effective Feb. 11, 1974. Amended: Filed Dec. 19, 1975, effective Dec. 29, 1975. Emergency amendment filed Jan. 17, 1977, effective Jan. 27, 1977, expired May 27, 1977. Amended: Filed Jan. 17, 1977, effective June 1, 1977. Emergency amendment filed March 15, 1978, effective March 25, 1978, expired July 23, 1978. Amended: Filed March 15, 1978, effective July 13, 1978. Amended: Filed July 5, 1978, effective Oct. 12, 1978. Amended: Filed July 13, 1978, effective Oct. 12, 1978. Amended: Filed Jan. 12, 1979, effective April 12, 1979. Amended: Filed May 27, 1981, effective Nov. 15, 1981. Amended: Filed Dec. 28, 1981, effective July 15, 1982. Amended: Filed Jan. 25, 1983, effective June 16, 1983. Amended: Filed Jan. 17, 1984, effective June 15, 1984. Amended: Filed Nov. 16, 1984, effective April 15, 1985. Amended: Filed Jan. 22, 1986, effective July 18, 1986. Amended: Filed May 4, 1987, effective July 24, 1987. Amended: Filed Feb. 2, 1988, effective April 28, 1988. Rescinded and readopted: Filed May 17, 1989, effective Dec. 15, 1989. Amended: Filed Oct. 7, 1994, effective

May 28, 1995. Amended: Filed April 9, 1998, effective Nov. 30, 1998. Amended: Filed December 14, 2000, effective May 30, 2001. Amended: Filed Oct. 15, 2007, effective April 30, 2008. ***Amended: Filed DATE.***

PUBLIC ENTITY COST: This proposed amendment will not cost state agencies or political subdivisions more than $500 in the aggregate.

PRIVATE ENTITY COST: This proposed amendment will not cost private entities more than $500 in the aggregate.

NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this Proposed Amendment with the Missouri Public Service Commission, Steven C. Reed, Secretary, Secretary, P.O. Box 360, Jefferson City, MO 65102. To be considered, comments must be received within thirty days after publication of this notice in the ***Missouri Register****. Comments should refer to Case No. ? and be filed with an original and eight (8) copies. No public hearing is scheduled.*