DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 192

[Docket PS-124; Notice 1]

RIN 2137-AC25

Regulatory Review; Gas Pipeline Safety Standards

Dated: July 15, 1992.

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: This notice proposes to change miscellaneous gas pipeline safety standards to provide clarity, eliminate unnecessary or overly burdensome requirements, and foster economic growth. The proposed changes result from the regulatory review RSPA carried out in response to the President's directive on reducing the burden of government regulation. The proposed changes would reduce costs in the gas pipeline industry without compromising safety.

DATES: RSPA invites interested persons to submit comments by September 30, 1992. Late filed comments will be considered as far as is practicable.

ADDRESSES: Send comments in duplicate to the Dockets Unit, Room 8421, Research and Special Programs Administration, U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590. Identify the docket and notice numbers stated in the heading of this notice. All comments and docketed material will be available for inspection and copying in room 8419 between 8:30 a.m. and 5 p.m. each business day.

FOR FURTHER INFORMATION CONTACT: A. Garnett, (202) 366–2392, regarding the subject matter of this notice, or the Dockets Unit, (202) 366–5046, regarding copies of this notice or other material that is referenced in this notice.

SUPPLEMENTARY INFORMATION:

Background

In a January 28, 1992, memorandum, President Bush wrote to Department and agency heads about the need to reduce the burden of government regulation. The President was concerned that agencies were not doing enough to review and revise existing regulations to eliminate unnecessary and overly burdensome requirements. He recognized that regulations that do not keep pace with new technologies and innovations impose needless costs and impede economic growth.

The memorandum called for a 90-day moratorium on issuing certain proposed or final regulations. The President asked agencies to use that period to review their existing regulations to identify those that are not cost-effective and to determine which could be more goal-oriented, could include market mechanisms, and could be clearer to avoid needless litigation. Each agency was asked to propose, as soon as possible, administrative changes to correct any problems the review found.

In response to the President's memorandum, DOT published a notice requesting public comment on the Department's regulatory programs (57 FR 4745; Feb. 7, 1992). Commenters were asked to identify regulations that substantially impede economic growth, may no longer be necessary, are unnecessarily burdensome, impose needless costs or red tape, or overlap or conflict with other DOT or Federal regulations. The deadline for submitting comments was March 2, 1992.

RSPA received comments from 39 persons and organizations about the pipeline safety regulations in part 192. Most of the comments came from regulated pipeline companies, pipeline trade associations, and state pipeline safety agencies. RSPA has carefully considered all the comments in its review of the regulations. Some comments will be considered in future rulemakings. Additionally, RSPA is preparing a separate rulemaking "Update of Standards Incorporated by Reference" which updates the editions of the industry standards that are set out in part 192.

One suggested change to part 192 that requires further study involves small gas distribution systems, such as master meter systems and petroleum gas systems serving mobile home or apartment complexes. The National Association of Pipeline Safety Representatives has recommended that RSPA develop separate, more appropriate safety standards for these systems in a new part to title 49 of the Code of Federal Regulations. RSPA invites persons interested in this topic to comment on whether such standards should be published.

Of the various pipeline regulations, the review showed that changes to the gas regulations in part 192 would result in the largest single cost savings. Therefore, changes to part 192 have the highest priority.

By memorandum of April 29, 1992, the President continued the moratorium on certain proposed and final regulations for 4 more months. With regard to the review of existing regulations, he requested that agencies publish proposed changes that require public comment as soon as possible.

Proposed Changes to Part 192 Safety Standards

The following discussion explains the changes RSPA proposes to various standards in part 192:

Section 192.1(b)(1) Scope of part. This section currently states that part 192 does not apply to the offshore gathering of gas upstream from the outlet flange of each facility on the outer continental shelf (OCS) where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream. RSPA proposes to delete the phrase "on the outer continental shelf", and to apply to the same exception to similar pipelines in state offshore waters.

The current regulations are not clear where the applicability of part 192 begins on offshore gathering lines in state waters. Shell Offshore, Inc. proposed a similar change in comments to an NPRM proposing to better define gathering lines (56 FR 48505; September 25, 1991; Docket PS–122).

This revision will clarify that part 192 does not apply to field production lines, i.e., flow lines, in state offshore waters, similar to the present exception on the OCS. Part 192 regulations are currently being applied to some production lines in state offshore waters where such regulations were not intended to apply. The drug testing requirements in part 199 are also being applied to workers on some production platforms in state offshore waters where such regulations were not intended to apply. The proposed revision would make federal and state offshore rules consistent and should reduce operating expenses for the operator.

Section 192.3 Definitions (transmission line). In part 192, the term "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 or storage facility; (b) operates at a hoop stress of 20 percent or more of SMYS; or (c) transports gas within a storage field." This definition was based on the definition of "transmission line" in the 1968 edition of the *USAS B31.8 Code.* Although DOT intended the part 192 definition to have the same meaning as the B31.8 Code definition, the part 192 definition omits the term "large volume customer," which marked an end of a transmission line in the B31.8 Code definition. Despite the omission, RSPA has interpreted the part 129 definition of transmission line to include pipelines that transport gas from gathering lines or transmission lines to large volume customers, such as a power plant or factory. RSPA proposes to clarify this application of part 192 by adding the term "large volume customer" to the transmission line definition in § 192.3.

The definition of Secretary would be amended to eliminate the connotation of gender.

Section 192.5 Class locations. Section 192.5 classifies the location of onshore pipelines on a scale that increases from 1 to 4 according to the number of buildings in an area. The area extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. However, if the area contains a cluster of buildings that by itself would qualify the area as Class 2 or 3, § 192.5(f) provides that the classification ends 220 yards from the nearest building in the cluster.

Comments from Enron Corporation, Northern Illinois Gas, and the RSPA internal regulatory review, indicated that some operators may not understand this cluster exception and add all the buildings in a 1-mile area to those in any cluster, determining a higher than required classification for the area. Because part 192 regulates pipelines more stringently as class location increases, any over-classification results in needless expenditures. RSPA proposes to clarify § 192.5 to minimize the possibility of over-classification of pipeline locations.

Section 192.7 Incorporation by reference. Section 192.7 sets out the general requirements for the incorporation in the regulations of industry standards for the design, construction and operation of gas pipelines. Paragraph 192.7(a) states that incorporation of a document by reference has the same force as if the document were copied in the regulations. Some operators have misinterpreted this section to mean that they must comply with all of the terms contained in a referenced document. RSPA proposes to revise § 192.7(a) to clarify that an entire standard is not incorporated when the document is incorporated by reference; rather, only those portions specifically referenced in the regulations are incorporated.

Section 192.9 Gathering lines. This section requires operators of gathering lines to comply with part 192 standards applicable to transmission lines. The requirements do not apply, however, to certain rural gathering lines that part 192 does not cover, as provided in § 192.1(b). Section 192.9 would be revised to highlight this limit on applicability. With a clear understanding of which gathering lines must meet transmission line requirements, operators should improve the efficiency of their compliance efforts. The proposed change would not reduce safety because it does not alter the scope of the existing regulation.

Section 192.11 Petroleum Gas Systems. (Also includes changes to §§ 192.1 and 192.3): Section 192.11 requires petroleum gas systems covered by part 192 to comply with National Fire Protection Association (NFPA) Standards No. 58 and No. 59 and other part 192 standards. Petroleum gas systems are pipeline distribution systems comprised of a liquefied petroleum gas (LPG) storage tank (or cylinder), piping, and other facilities to distribute petroleum gas (instead of natural gas) to customers who consume the gas. The systems covered are those that serve 10 or more customers, or fewer than 10 if any portion of the system is in a public place. However, RSPA has interpreted § 192.11 not to apply to systems where a single tank serves a single customer on the customer's premises even if part of the system is in a public place.

Petroleum gas is defined in § 192.11(c) as "propane, butane, or mixtures of these gases, other than a gas air mixture that is used to supplement supplies in a natural gas distribution system." Because of the petroleum "gas air mixture" exclusion, which was intended to exclude from § 192.11 natural gas distribution systems that transport such mixtures, RSPA has not enforced NFPA Standards No. 58 and No. 59 against LPG peak shaving plants. Operators of natural gas systems use LPG peak shaving plants in cold weather to augment natural gas supplies with mixtures of petroleum gas and air. Nevertheless, we have said these plants are pipeline facilities subject to all other requirements of part 192; there is no doubt NFPA intended Standards No. 58 and 59 to cover such plants.

NFPA petitioned RSPA to clarify the coverage of NFPA Standards No. 58 and No. 59 under § 192.11 (P-44; November 30, 1989). NFPA also requested that the definition of petroleum gas be amended to be more consistent with the definitions used in the NFPA standards. The Florida LP Gas Pipeline Advisory Committee (see Hillsboro Gas Company comments in Docket RR-1), an industry group that advises the Florida Division of Liquefied Petroleum Gas, the state regulatory agency on LPG matters, supported the petition. Because both pipeline industry and state safety officials have had difficulty understanding the existing rule, RSPA agrees that revisions are needed.

RSPA proposes to revise § 192.11(a) to provide that LPG peak shaving plants must comply with NFPA Standards No. 58 and No. 59 and the applicable part 192 standards. NFPA Standards No. 58 and No. 59 would not apply to natural gas distribution systems downstream from the point where petroleum gas/air mixtures are combined with natural gas. Section 192.11(b) would be revised to clarify that all regulated petroleum gas systems, including systems that carry petroleum gas and air mixtures, must meet NFPA Standards No. 58 and No. 59 and other applicable part 192 standards. The current rule that part 192 prevails if a conflict exists with an NFPA requirement would be revised under a proposed revision of § 192.11(c) to provide that the NFPA requirement would prevail. RSPA's experience shows the NFPA rules are updated regularly to include state of the art technology and should be given priority. However, if the NFPA standards are silent or nonspecific (such as for corrosion protection of the system), the operator would be required to comply with part 192 requirements.

In addition, this notice proposes to redefine "petroleum gas" to be consistent with current commercial usage. The changes should reduce confusion in knowing which standard to follow, and should result in increased operator efficiency in designing, operating and maintaining petroleum gas systems. The revised definition would appear in § 192.3 instead of § 192.11. Also, those petroleum gas systems that are not subject to part 192 would be stated in § 192.1, "Scope of part," instead of § 192.11.

RSPA currently incorporates by reference the 1979 editions of NFPA Standards No. 58 and 59, as shown in appendix A of part 192. The 1979 edition of NFPA Standard No. 58 does not permit the use of mechanical fittings for making polyethylene joints. In a concurrent rulemaking (referenced above), RSPA is updating appendix A to incorporate the 1992 edition of NFPA Standard 58, which allows the use of mechanical fittings for certain pipe. RSPA will not enforce the prohibition against mechanical fittings on these pipe in the interim should this rulemaking be concluded before the appendix is updated.

Section 192.14 Conversion to service subject to this part. (Also includes changes to § 192.553 General requirements.): Section 192.14 establishes various criteria for qualifying a pipeline previously used in service not subject to part 192 for use under part 192. Section 192.14(a)(1) requires that the design 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. Section 192.14(a)(4) requires that the pipe must be hydrostatically tested in accordance with subpart J to substantiate the maximum allowable operating pressure (MAOP) permitted by subpart L.

Section 192.553 establishes general requirements for increasing the MAOP (uprating) a pipeline. Section 192.553(d) limits a new MAOP established under part 192 to the maximum that would be allowed under part 192 for a new segment of pipeline constructed of the same materials in the same location. Neither section provides for verifying design calculations or limiting MAOP when one or more of the steel pipe variables necessary for the determination of design strength or MAOP are unknown.

ANR Pipeline Company suggested using a hydrostatic test to establish the yield strength of pipelines for which yield strength is not known. The ASME B31.8 Code does not directly provide for hydrostatic testing to determine the yield strength of pipe (ASME B31.8 Code for Pressure Piping for Gas Transmission and Distribution Systems), paragraph 845.214, Qualification of a Steel Pipeline or Main to Establish the MAOP). However, the Code provides for establishing MAOP on the basis of hydrostatic testing of existing natural gas pipelines or of pipelines being converted to natural gas service where one or more of the factors in the design formula are unknown. The test pressure used in the referenced Code MAOP calculation is limited to the test pressure obtained at the high elevation point of the minimum strength test segment and to the pressure required to produce a stress equal to the yield strength as determined by hydrostatic testing. The procedure for determining yield strength by hydrostatic testing is included in B31.8 appendix N, Recommended Practice for Hydrostatic Testing Pipelines in Place.

RSPA proposes to change §§ 192.14(a)(1) and 192.553(d) to permit verifying the design pressure and establishing a new MAOP for steel pipelines when one or more of the variables necessary for determining those pressures are unknown by (1) testing the pipeline in accordance with ASME B31.8, appendix N, to produce a pressure equal to yield strength, and (2) applying to not more than 80 percent of the first pressure that produces yielding the appropriate factors in § 192.619(a)(2)(ii) and proposed § 192.619(a)(2)(iii).

The proposed change will enable the conversion or uprating of certain pipelines, or reduce the cost of conversion or uprating of certain pipelines, and will enable the operation of the lines at their fullest potential.

The proposed change should not have an adverse effect on pipeline safety. To determine the MAOP at a stress equivalent to the yield strength of the pipe in the affected pipelines, testing the lines to hydrostatic pressures greater than otherwise required for the determination of the MAOP under § 192.619 will be necessary. The result will be a greater margin of safety between hydrostatic test pressure and MAOP. Any defects present in the pipeline will likely fail during hydrostatic testing and be removed from the line.

Section 192.107 Yield strength (S) for steel pipe. Paragraph 192.107(b) provides that, for pipe that is manufactured in accordance with a specification not listed in section I of part 192's appendix B or whose specification or tensile properties are unknown, the yield strength (S) to be used in the design formula in § 192.105 is the lower of the following criteria if the pipe is tensile tested in accordance with section II–D of appendix B:

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

(ii) The lowest yield strength determined by the tensile tests, but not more than 52,000 p.s.i.

ANR Pipeline Company (ANR) suggested that the yield strength limitation in § 192.107(b)(1)(ii) to a maximum of 52,000 p.s.i. is out-dated. The 52,000 p.s.i. yield strength limit was developed and published in the ASME B31.8 Code for Pressure Piping, Gas Transmission and Distribution Piping Systems when the highest strength pipe commercially available had a specified minimum yield strength (SMYS) of 52,000 p.s.i. ANR argued that since then, pipe materials with higher yield strengths of 60,000, 65,000 and 70,000 p.s.i. have become commercially available and due to the current limitation, good, conditioned pipe lacking tensile property documentation is being under-utilized. ANR suggested that the maximum of 52,000 p.s.i. be increased to a value reflecting current pipe usage.

Instead, RSPA is proposing to remove the 52,000 p.s.i. SMYS limitation. By permitting an increase in the maximum value of the minimum yield strength determined by tensile test, utilizing a higher "S" value that is more representative of the true properties of the material as the basis for design will be possible. An increase will permit the use of some pipe lacking original tensile property documentation in higher design pressure applications where the only current alternative is the purchase of new pipe at market prices.

This change will have no impact on pipeline safety. If the maximum value of 52,000 p.s.i. were deleted as proposed, the two remaining § 192.107(b)(1) alternative criteria for the design value would provide adequate limitation of the yield strength used for design. The normal statistical distribution of yield strength for a uniform lot of steel pipe is such that a value equal to 80 percent of the average yield strength determined by tensile test usually will be less than the specified minimum yield strength. For example, unidentified pipe originally made as Grade X65 (65,000 p.s.i. SMYS) with an average mill test yield strength of 78,000 p.s.i., an exceptionally high average, could be used in the design formula as 62,400 p.s.i. A lower average yield strength determined by tensile test would result in a design yield strength less than 62,400 p.s.i. The alternative criterion, based on the lowest actual yield strength determined by test, is unlikely to be less than 80 percent of the average yield strength, except in the case of a lot of pipe with exceptionally high scatter in the test results, in which case the alternative protects against an average based on a skewed statistical distribution. Under either criteria, the yield strength value determined by test for use in the design formula will provide a reasonable conservative design pressure.

Section 192.121 Design of plastic pipe. This regulation establishes the design pressure for plastic pipe in accordance with the design formula, specified in § 192.121, and design limitations specified in § 192.123. RSPA recommends that an alternative formula, commonly used by industry, be added to provide greater flexibility and consistency with industry practices. The following formula would be added to § 192.121 to provide an alternative method of determining the design pressure for plastic pipe based on the Standard Dimension Ratio (SDR), often marked on the exterior surface of plastic pipe:

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

The SDR, a common industry parameter, is the ratio of average specified outside diameter to minimum specified wall thickness in accordance with a preferred numbering system.

This proposed alternative formula would not compromise pipeline safety because it produces identical results to the existing formula. This formula differs only in its use of the SDR which avoids having to determine the outside diameter and wall thickness of the pipe.

Section 192.123 Design limitations for plastic pipe. This regulation establishes design limitations for the use of plastic pipe in natural gas pipelines. Several operators recommended that § 192.123(b)(1) be amended to reflect advancements in plastic pipe technology proven to provide safe transportation of natural gas by pipeline at temperatures below the current limit of −20°F RSPA proposes to lower the existing operating temperature limit from −20°F to −40°F, to give operators greater liberty in selecting plastic pipe for use in natural gas pipelines. In November 1979, RSPA granted a waiver to this regulation. Additionally, RSPA proposes to clarity § 192.123(b)(2). This section sets the maximum operating temperature for thermoplastic and reinforced plastic pipe to the temperature at which the long-term hydrostatic strength was determined. For pipelines manufactured before May 18, 1978, this section permits operation at temperatures up to 100°F even if the long-term hydrostatic strength was not determined at that temperature. RSPA proposes to amend § 192.123(b)(2) to clarify the upper operating temperature limit for thermoplastic pipe. The proposed change will not affect pipeline safety; rather, it clarifies the regulation in order to reduce misinterpretation.

Section 192.179 Transmission line valves. This rule establishes standards for spacing of transmission line sectionalizing block valves according to population density in the vicinity of the pipeline. ANR Pipeline Company stated that the current requirement for fixed valve spacing does not make sense and imposes needless costs. ANR proposed that the regulation be changed to permit the operator to determine the valve spacing. ANR said that initial damage is done within a very short time after a pipeline failure and that the spacing of valves will not limit the initial damage. ANR further stated that there is no danger to the public since natural gas is lighter than air, and the gas flowing from the pipeline will normally travel up (directly into the atmosphere) from the failure site.

RSPA recognizes that transmission line sectionalizing block valves are expensive; however, RSPA believes they are necessary to ensure pipeline safety. Therefore, to reconcile these competing interests, RSPA proposes to revise § 192.179(a) to allow the Administrator to approve other spacing of the sectionalizing block valves in those segments of a transmission line where the operator demonstrates a resulting equivalent level of pipeline safety. This revision accelerates the approval process and may reduce pipeline installation costs.

Section 192.203 Instrument, control, and sampling pipe and components. Section 192.203(b)(2) requires the installation of a shutoff valve in each takeoff line of a regulator station. The regulator controls line pressure downstream from the regulator. Mooney Controls, a manufacturer of pre-piped regulators and valves, petitioned that the requirement to install control valves on pre-piped regulators and valves be changed. Mooney's petition followed a Missouri Public Service Commission grant of waiver exempting the City of Perryville, Missouri from installing such valves on their system. Perryville's regulators are not pre-piped. RSPA proposes to revise the regulation to require shutoff valves only in those regulator stations, pre-piped or otherwise, where necessary to isolate the regulator from gas line pressure. The main purpose of the shutoff valve is for testing the regulator to insure its functions properly; therefore, RSPA expects no loss of safety if the station can be isolated between inlet and outlet valves.

Section 192.227 Qualification of welders and § 192.229 Limitations on welders. Welders qualified under § 192.227(a) are required under § 192.229 to requalify every 6 months, and welders qualified under § 192.227(b) are required to requalify every 15 months. Moreover, § 192.227(b) qualification is less comprehensive than qualification under § 192.227(a) because welders who qualify under § 192.227(b) may only weld on pipe that will be subjected to a hoop stress of less than 20 percent of SMYS. The Minnesota Office of Pipeline Safety (MnOPS) stated that many Minnesota operators would like to qualify welders under § 192.227(a) because those qualification requirements provide a better indication of the quality of the test weld. MnOPS also stated that operators would like the option to requalify under § 192.227(b) those who weld only on lines operating at less than 20 percent of SMYS. MnOPS believes that requalification requirements should be more appropriately based on the stress level of the pipe being welded rather than on the initial qualification.

Thus, RSPA proposes to revise §§ 192.227 and 192.229 to allow those who weld on lines operating at less than 20 percent of SMYS to qualify initially under either § 192.227(a) or § 192.227(b) and requalify under § 192.227(b). Those who weld under § 192.227(a) requirements would still be required to requalify under § 192.227(a). Pipeline safety would not be compromised, the rules would be more flexible, and compliance costs would be reduced.

Section 192.241 Inspection and test of welds. Section 192.241 establishes the requirements for inspection and test of welds made on steel materials in pipelines except welds that occur during the manufacture of pipe and pipeline components. Under paragraph (c), the acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 6 of API Standard 1104. In response to a petition by the American Petroleum Institute (API), the Seventeenth Edition of API Standard 1104, except the appendix, was incorporated by reference in parts 192, 193, and 195 by notice in the Federal Register (54 FR 27881; July 3, 1989). The appendix provides more liberal acceptance standards for certain weld flaws based on widely accepted fracture mechanics principles. In its notice, RSPA stated that the fracture mechanics model contained in the appendix could not be adopted as a Federal weld acceptance standard without the opportunity for public comment.

The American Gas Association, Midcon Corporation, and the internal regulatory review suggest that incorporation by reference should include the appendix, as requested in API's petition. API's petition was supported by research that confirmed the conservatism of the fundamental approach for flaw assessment in the appendix.

Accordingly, RSPA proposes to modify § 192.241(c) to permit the use of the appendix in API Standard 1104 as an alternative acceptance standard for flaws, except cracks, in girth welds. RSPA proposes to except cracks from evaluation under the Appendix because a crack is a flaw that results from a localized stress that is greater than the strength of the steel and that has the potential to increase in size when subjected to additional stress. Also, accurate measurement of the depth of a crack, a measurement needed for evaluation, is difficult.

By allowing the operator to elect to use the Appendix for certain pipelines, the proposed change will reduce construction costs by eliminating the need to make weld repairs or replacements otherwise required under API section 6. The proposed change affects only acceptance criteria for girth welds. Historically, defects in girth welds are an infrequent contributor to pipeline accidents. Furthermore, considering the conservatism attributed to the approach to flaw assessment in the appendix, the proposed change should have no detrimental effect on pipeline safety or the environment.

Section 192.243 Nondestructive testing. Paragraph (d)(4) requires the 100 percent nondestructive testing at pipeline tie-ins of the field butt welds covered under paragraph (d). RSPA proposes to amend paragraph (d)(4) to add the phrase "including tie-ins of replacement sections." The proposed revision would improve clarity and understanding of the interpretation of "tie-ins." However, the proposed revision would not compromise safety because the change merely improves understanding of the intent of the regulation.

Section 192.281 Plastic pipe. This rule establishes minimum requirements for joining plastic pipe. Section 192.281(c) would be revised to include electrofusion as an accepted method of heat-fusion for joining polyethylene pipe. The proposed change would reduce regulatory burden by expanding the options available to operators for joining polyethylene pipe. Pipeline safety would not be compromised by adopting electrofusion because it is already widely used in the pipeline industry and has proven to work safely and reliably to join polyethylene pipe.

Section 192.283 Plastic pipe; qualifying joining procedures. This section establishes criteria for qualification of joining procedures for plastic pipe. RSPA proposes adopting the ASTM F1055–87 standards for joining polyethylene plastic pipe by electrofusion, and adding ASTM Standard F1055–87 to appendix A.II.B. Adoption of this standard would provide operators greater flexibility in selecting methods for joining polyethylene pipe. However, the proposal would not compromise pipeline safety because electrofusion is already in widespread use and its history of application has not revealed any risk to the safe transportation of natural gas.

Section 192.317(a) Protection from hazards. This section requires that gas transmission lines and mains be protected from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or sustain abnormal loads. Additionally, offshore pipelines must be protected from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations. RSPA recognizes that some gas pipelines are in locations where complete protection of the pipe from the cited hazards is not feasible and proposes to change the regulation to recognize that reality. Therefore, this notice proposes to amend the section to require the operator to take all practicable steps to protect gas pipelines from the cited hazards. The proposed revision would not compromise safety but would avoid needless discussion over the interpretation of the phrase "must be protected," when applied to certain locations.

Sections 192.319(c) and 192.327(e) Burial of offshore pipe. Under § 192.319(c), all offshore pipe in water at least 12 feet deep but not more than 200 feet deep, as measured from the mean low tide, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. For offshore pipe installed under water less than 12 feet deep, as measured from mean low tide, § 192.327(e) requires a minimum cover of 36 inches in soil or 18 inches in consolidated rock, between the top of the pipe and the natural bottom, unless an underground structure prevents installation with the minimum cover, and the pipe is additionally protected to withstand anticipated external loads.

At the same time, a recently adopted rule, § 192.612(b)(3), requires operators to provide similar cover, without exception for underground structures, over pipelines in the Gulf of Mexico and its inlets under water less than 15 feet deep, if the pipelines are exposed or a hazard to navigation (Amendment 192–67; 56 FR 63764; Dec. 5, 1991). Section 192.3 defines "hazard to navigation" as "a pipeline where the top of the pipe is less than 12 inches below the seabed in water less than 15 feet deep, as measured from the mean low water." The term "Gulf of Mexico and its inlets" is defined to include only areas under 15 feet of water.

We see that § 192.319(c) is inconsistent with § 192.612(b)(3) for pipe in the Gulf of Mexico and its inlets under water less than 15 feet deep but at least 12 feet deep, because § 192.319(c) permits the pipe to be without cover or to be above the seabed if properly protected. Such pipe is a "hazard to navigation" under the definition of that term in § 192.3, and must have the minimum cover that § 192.612(b)(3) requires. In addition, § 192.327(e) is inconsistent with § 192.612(b)(3) for pipe in the Gulf of Mexico and its inlets under water less than 12 feet deep. In certain instances, § 192.327(e) allows that pipe to be without cover or less than 12 inches below the seabed, and neither condition is allowed under § 192.612(b)(3). In light of these inconsistencies, RSPA proposes to amend §§ 192.319(c) and 192.327(e) to correct the problem.

Section 192.321 Installation of plastic pipe. Paragraph (a) requires that plastic pipe be installed below ground level. RSPA proposes to allow, for a temporary period not exceeding 30 days, use of plastic pipe above ground level. The proposed revision would limit the use of the pipe to locations where it is unlikely to be damaged (or is protected from damage) by external forces. Moreover, the properties of the pipe must be suitable for its exposure to ultra violet light and temperature extremes. The proposed revision would provide the operator an option that may result in lower material and installation costs. However, safety would not be compromised because the temporary use of the pipe is limited to installations where the properties of the pipe are suitable for or protected from exposure and external forces.

Section 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971. Paragraph (a)(2) requires a pipeline to have a cathodic protection system designed to protect the pipeline in its entirety. RSPA recognizes that the phrase "in its entirety" is redundant and misleading, and proposes its removal. It is redundant because the term "pipeline" as used in part 192, means all facilities through which gas flows, unless otherwise specified. It is misleading because some operators understand the phrase to include metallic casings. But under the "pipeline" definition in § 192.3, a casing is not part of the pipeline. The proposed change would avoid confusion. However, the proposed revision would not compromise safety because it would merely express the intent of the regulation with greater clarity and certainty.

Paragraph (f)(1) states that the external corrosion control requirements do not apply to electrically isolated metal alloy fittings in plastic pipelines if for the size fitting used, an operator can show through various means that adequate corrosion control is provided by alloyage. RSPA recognizes that the word "alloyage" is not common usage and proposes its replacement with "alloy composition." to improve understanding.

Section 192.475 Internal corrosion control: General. Existing § 192.475(c) limits hydrogen sulfide content of natural gas stored in pipe-type or bottle-type holders to 0.1 grain per 100 standard cubic feet of gas. Columbia Gas Transmission Corporation proposed that the rule be relaxed to allow a concentration of 0.25 grain per 100 standard cubic feet of gas.

Because the 0.25 limit is within customary industry contract limits and is still lower than maximum allowable safe limits, RSPA proposes to increase the allowable hydrogen sulfide limit in gas to be stored in pipe-type and bottle-type holders to 0.25 grain per 100 standard cubic feet of gas. This action would lower the cost of processing natural gas that contains small quantities of hydrogen sulfide.

Section 192.485 Remedial measures: Transmission lines. Paragraph (a) requires that each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so clearly grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

Paragraph (b) requires that each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

RSPA recognizes that paragraphs (a) and (b) provide no guidance for an operator's use in determining the strength of the remaining wall thickness of corroded steel pipe. To provide this needed guidance, RSPA proposes the adoption of the ASME Manual B31G procedure for determining the remaining strength of corroded steel pipe in existing pipelines. Application of the procedure would be in accordance with the limitations set out in the B31G Manual. The proposal would provide guideline information as to whether a corroded region (not penetrating the pipe wall) may be left in service; an option that might require a reduction in maximum allowable operating pressure, but may be more economical than the replacement or repair of the corroded pipe. The proposed revision would not compromise safety because it merely accepts an established pipeline industry guideline, and does not impose any new requirements on the operators.

Section 192.491 Corrosion control records. Anode Locations. Paragraph (a) requires an operator to maintain records or maps showing the location of cathodically protected piping, cathodic protection facilities, other than unrecorded anodes installed before August 1, 1971, and neighboring structures bonded to the cathodic protection system. The Arizona Corporation Commission stated that records and maps showing the specific location of millions of individual galvanic anodes throughout the gas pipeline systems are not needed because many anodes have deteriorated and do not exist except for the connecting wire. Furthermore, Arizona said that the specific location of a galvanic anode is of little value to the operator or to pipeline safety.

RSPA proposes to eliminate this requirement. The proposed change would relieve operators of the burden of making precise field measurements and preparing and maintaining records and maps showing the specific location of millions of individual anodes. However, the proposed revision would not compromise safety because records or maps can show that a stated number of anodes were installed in a certain manner or spacing between particular reference points along the pipeline. Moreover, it is more common and practical to use electrical measurements to determine individual locations if locating individual anodes is necessary.

Record Retention

Under § 192.491(b), the retention period for records of corrosion control tests, surveys, and inspections is the service life of the pipeline. Several pipeline companies suggested we consider shortening this period as a cost saving measure that would not compromise safety.

Besides indicating compliance with the corrosion control standards, records of required tests, surveys, and inspections provide a history that is useful in analyzing corrosion problems that may arise. For some required corrosion control records, a 5-year retention period is adequate for these purposes. However, records used to determine the need for protection provide a valuable basis for comparison with later data and should be retained for the service life of the pipeline. Therefore, the minimum retention period for corrosion control records would be set at 5 years under a proposed change to § 192.491, except that certain data involving corrosion control determinations would still have to be kept for as long as the pipeline remains in service.

Section 192.553 General Requirements. (see previous discussion under § 192.14).

Section 192.607 Determination of class location and maximum allowable operating pressure. This rule required operators to determine the maximum allowable operating pressure, class location, and concurrence of associated hoop stress with class location requirements for segments of pipe which produce hoop stress in excess of 40 percent SMYS. For pipelines with hoop stress not commensurate with applicable class location requirements, the rule required operators to confirm or revise the maximum allowable operating pressures. These determinations had to be completed before April 15, 1971. Subsequent work was required to be completed before July 1973 or December 1974.

The South Carolina Public Service Commission recommended that this regulation be deleted because the time periods for completing the studies and compliance work has passed. Deleting this rule would eliminate irrelevant citations and simplify the remaining applicable regulations. Pipeline safety would not be compromised because the rule no longer has application.

Section 192.611 Change in class location. This section requires confirmation or revision of a pipeline's maximum allowable operating pressure (MAOP) within 18 months after a change in class location. As § 192.611(a)(3)(ii) provides, the MAOP that results from confirmation or revision under § 192.611 may not exceed the pipeline's previous MAOP. Any increase in a pipeline's MAOP must be accomplished under the uprating requirements of part 192's subpart K, not § 192.611. However, Enron Corporation pointed out that designating this restriction as § 192.611(a)(3)(ii) suggests that it applies only to confirmations or revisions under paragraph (a)(3), which is not the intent. Therefore, § 192.611(a)(3)(ii) would be redesignated as § 192.611(b), and the existing paragraphs (b) and (c) redesignated as (c) and (d), respectively. Because the proposed change is for clarification only, safety would not be compromised.

Section 192.614 Damage prevention program. Paragraph (b)(2) requires notification of the public in the vicinity of the pipeline and actual notification of persons who normally engage in excavation activities in the area in which the pipeline is located of the damage prevention program's existence, purpose, and how to learn the location of underground gas pipelines before excavation activities are started. While the paragraph states that "actual" notification is to be given these excavators, no corresponding adjective describes the notification to be given the public in the vicinity of the pipeline. RSPA proposes the insertion of the word "general" to clarify that notification need only be provided by articles or announcements in newspapers, radio or television or other medium of mass communication which are appropriate for the public in the vicinity of the pipeline. The proposed revision would avoid confusion. However, safety would not be compromised because the revision merely expresses the intent of the regulation with greater clarity and certainty.

Section 192.619 Maximum allowable operating pressure: Steel or plastic pipelines. This section establishes various criteria for determining the maximum allowable operating pressure (MAOP) of steel or plastic pipelines, the lowest of which limits the MAOP. Paragraph (a)(4) limits MAOP for furnace butt welded steel pipe to a maximum of 60 percent of the mill test pressure, the same percent applied as the longitudinal joint factor (E) in the design formula under § § 192.105 and 192.113. Paragraph (a)(5) limits MAOP for steel pipe other than furnace butt welded pipe to a maximum of 85 percent of the highest test pressure to which the pipe has been subjected, whether by mill test or by the post installation test.

Enron Corporation proposed that § 192.619(a)(4) and (5) be deleted because mill tests are a quality control test during manufacture. ENRON argued that the only test affects the determination of MAOP should be the in-place hydrostatic strength test.

RSPA proposes to delete § 192.619(a)(4) and (5), but to add a paragraph (a)(2)(iii) applying the longitudinal joint factors for furnace butt welded and lap welded pipe in addition to the appropriate class location factor. The (a)(4) criterion which limits the MAOP of furnace butt welded steel pipe to 60 percent of the mill test pressure will be the applicable criterion in many installations because mill test pressures for this pipe are very low compared to specified minimum yield strength (SMYS). If § 192.619(a)(4) were deleted, no factor would remain to compensate for the low joint efficiency factor assigned to furnace butt welded pipe under § 192.113. For other than furnace butt welded steel pipe, the criterion of limiting MAOP to 85 percent of the mill test pressure is likely to be the applicable criterion for relatively small diameter pipe, because mill test pressure is based on 75 percent of SMYS, unless the operator has elected to test the pipe after construction to a pressure much lower than permitted by the design formula under § 192.105. The current regulations do not consider that § 192.619(a)(5) includes furnace lap welded pipe, which is no longer manufactured but remains in service. When such pipe was available for new construction, the joint efficiency factor for design was 0.8 or 80 percent of SMYS.

The proposed change will permit the operation of many pipelines with furnace butt welded pipe and some with non-furnace butt welded smaller diameter pipe at pressures higher than presently permitted on the basis of mill test pressure. This should result in reduced operating costs for those pipelines. The remaining limitations on MAOP and the application of the longitudinal joint factor in § 192.619(a)(2)(iii) adequately provide for the safe operation of the pipelines affected.

Section 192.625 Odorization of gas. The Oregon Public Utility Commission (Oregon) commented that master meter operators should be exempted from § 192.625(f) which requires sampling of gas to assure the gas contains the proper concentration of odorant. Oregon stated that master meter operators receive their gas from operators who verify by odorometer that the gas is meeting the one-fifth LEL requirement and that it is unnecessarily burdensome for these operators to buy an odorometer or to hire consultants to do this testing. Oregon suggested that instead of an expensive odorometer test, the master meter operator could be required to conduct a "sniff" test. Oregon estimated a savings of 98 percent in consulting fees.

RSPA currently allows master meter operators to (1) have the company that sells them the gas verify by records or tests that the gas meets the required criteria or (2) have a qualified person, the gas utility company, or transmission company, run an odorometer test of the gas in the system. This procedure is spelled out in the Guidance Manual for Operators of Small Gas Systems, U.S. Department of Transportation, 1991. The Manual further states that periodic "sniff" test can be a guide in determining odorization levels even though they do not replace the need to maintain odorant usage records or perform odorometer tests.

Accordingly, the rule proposes that master meter operators may comply with §§ 192.625(a) and (f) by (1) receiving written verification from their gas supplier that gas odorization levels are sufficient, and (2) conducting periodic "sniff" tests to confirm supplier's findings. These "sniff" tests should be run at the outer ends of the system. The operator must document the specific procedures in its Operating and Maintenance (O&M) plan and keep records of the tests, including dates, names and locations. Since some master meter operators are not aware of the flexibility provided in the manual, the proposal should reduce the cost of compliance for those operators.

Section 192.705 Transmission lines: Patrolling. Paragraph (a) requires an operator to have a patrol program to observe cited surface conditions on and adjacent to its gas transmission line right-of-way for indications of activities and other factors affecting the safety and operation of the pipeline. RSPA proposes that the section be changed to indicate that aerial patrols are an optional method of compliance. The proposed change would provide a more effective option for some operators, who may not be aware that aerial patrols of gas transmission lines are acceptable. The proposed revision would not compromise safety because some surface condition activities adjacent to the right-of-way, that affect safety and operation of pipelines, are more visible from an aerial patrol than from walking or driving the right-of-way.

Section 192.709 Transmission lines: Record keeping. Section 192.709 requires operators to keep various records about transmission lines for as long as the line remains in service. ANR Pipeline, Enron Corporation, and the Interstate Natural Gas Association of America suggested this lengthy record retention period could be significantly shortened with no adverse effect on safety. RSPA has considered changes that would not affect the usefulness of these records in determining an operator's level of compliance effort or in constructing the history of an accident or safety problem. Therefore, RSPA is proposing to adopt a 5-year retention period for records of patrols, surveys, inspections and tests. A 5-year retention requirement would assure that these records are on hand during the normal cycle of routine inspection visits by RSPA field inspection personnel. Also, the current service-life retention period appears unnecessary for records of repairs on facilities other than pipe. A retention period of 1 year would be established for such records. Section 192.709 also would be changed to clarify the information to be recorded.

Section 192.721 Distribution systems: Patrolling. This section governs the frequency at which operators must patrol mains in distribution systems. The regulation is written in performance terms, except that mains located where anticipated movement or loading could cause leakage must be patrolled at intervals not exceeding 4½ months, but at least four times a year. Northern Illinois Gas recommended that we adopt a more moderate patrol frequency as a cost saving measure, but did not recommend an alternative. The option we are considering is twice a year for mains in Class 1 or 2 locations. The lower frequency would correspond to the lower risk in these less densely populated locations. Twice a year checks also would match the frequency at which operators must patrol transmission lines at highway and railroad crossings in Class 1 and 2 locations (§ 192.705). Because these transmission line crossings pose a high level of risk, and twice-a-year patrols have proved satisfactory, RSPA believes the proposed change to § 192.721 would not reduce safety.

Rulemaking Analyses

Paperwork Reduction Act

The documentation for the information collection requirements for part 192 was submitted to the Office of Management and Budget (OMB) during the original rulemaking processes. Currently, regulations in part 192 are covered by OMB Control Numbers 2137–0049 (approved through October 31, 1994) and 2137–0583 (approved through May 31, 1994). This notice proposed no additional information collection requirements. Instead, the notice proposed to relax the information collection or retention and record retention burden on pipeline operators (described above). Accordingly, there is no need to repeat those submissions with this notice of proposed rulemaking.

Executive Order 12291 and DOT Regulatory Policies and Procedures

RSPA has concluded that this proposal is not a major rule under Executive Order 12291. However, it is "significant" under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979) because of the interest expressed by the President and the substantial interest by the pipeline industry.

A Regulatory Evaluation has been prepared and is available in the docket. RSPA estimates the proposed changes to existing rules would result in savings of $33,000,000 per year without associated costs and with no adverse effect on safety. As discussed above, these savings would come largely from the use of new technology, greater flexibility in constructing, maintaining, and operating pipelines, improved clarity, and the elimination of burdensome regulations.

Regulatory Flexibility Act

RSPA criteria for small companies or entities are those with less than $1,000,000 in revenues and are independently owned and operated. Few of the companies subject to this rulemaking meet these criteria. However, RSPA seeks such impact information in response to this rulemaking. Accordingly, based on the facts available concerning the impact of this proposal, I certify under section 605 of the Regulatory Flexibility Act that this proposal would not, if adopted as final, have a significant economic impact on a substantial number of small entities.

Executive Order 12612

RSPA has analyzed the proposed rules under the criteria of Executive Order 12612 (52 FR 41685; October 30, 1987). We find it does not warrant preparation of a Federalism Assessment.

List of Subjects in 49 CFR Part 192

Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, RSPA proposes to amend 49 CFR part 192 as follows:

PART 192—[AMENDED]

1. The authority citation for part 192 continues to read as follows:

Authority: 49 App. U.S.C. 1672 and 1804; 49 CFR 1.53.

2. Section 192.1 would be amended by revising paragraph (b)(1) and adding paragraph (b)(4) to read as follows:

§ 192.1 Scope of part.

* * * * *

(b) This part does not apply to:

(1) Offshore pipelines upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed whichever facility is farther downstream; and

* * * * *

(4) Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—

(i) Fewer than 10 customers, if no portion of the system is located in a public place; or

(ii) A single customer, if the system has only one tank and the system is located entirely on the customer's premises, regardless of whether a portion of the system is located in a public place.

3. In § 192.3, a definition of "petroleum gas" would be added and the definitions of "secretary" and "transmission line" would be revised to read as follows:

§ 192.3 Definitions.

* * * * *

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 at 100 degrees F.

* * * * *

Secretary means the Secretary of Transportation or any person to whom the Secretary has delegated authority in the matter concerned.

* * * * *

Transmission line means a pipeline, other than a gathering line, that:

(1) Transports gas from a gathering line or storage facility to a distribution center, large volume customer, or storage facility;

(2) Operates at a hoop stress of 20 percent or more of SMYS; or

(3) Transports gas within a storage field.

* * * * *

4. Section 192.5 would be revised to read as follows:

§ 192.5 Class locations.

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

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

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

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

(1) A Class 1 location is:

(i) An offshore area; or

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

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

(3) A Class 3 location is

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

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

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

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

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

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

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

5. Section 192.7 would be amended by revising paragraph (a) to read as follows:

§ 192.7 Incorporation by reference.

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

* * * * *

6. Section 192.9 would be revised to read as follows:

§ 192.9 Gathering lines.

Each operator of a gathering line, except as provided in § 192.1, must comply with the requirements of this part applicable to transmission lines.

7. Section 192.11 would be revised to read as follows:

§ 192.11 Petroleum gas systems.

(a) Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and NFPA Standards No. 58 and No. 59.

(b) Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and of NFPA Standards No. 58 and No. 59.

(c) In the event of a conflict between this part and the requirements of NFPA Standards No. 58 and No. 59, NFPA Standards No. 58 and No. 59 prevail.

8. Section 192.14 would be amended by revising paragraph (a)(1) to read as follows:

§ 192.14 Conversion to service subject to this part.

(a) * * *

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in satisfactory condition for safe operation. If one or more of the variables for a steel pipeline necessary to verify the design pressure under § 192.105 or to perform the testing under paragraph (a)(4) of this section are unknown, the design pressure may be verified and the MAOP determined by:

(i) Testing the pipeline in accordance with ASME B31.8 Code, Appendix N, to produce a stress equal to the yield strength, and

(ii) Applying, to not more than 80 percent of the first pressure that produces a yielding, the appropriate factors in §§ 192.619(a)(2)(ii) and (a)(2)(iii).

* * * * *

9. Section 192.107 would be amended by revising paragraph (b)(1) introductory text and paragraph (b)(1)(ii) to read as follows:

§ 192.107 Yield strength (S) for steel pipe.

* * * * *

(b) * * *

(1) If the pipe is tensile tested in accordance with section II–D of appendix B to this part, the lower of the following:

* * * * *

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

* * * * *

10. Section 192.121 would be revised to read as follows:

§ 192.121 Design of plastic pipe.

Subject to the limitations of § 192.123, the design pressure for plastic pipe is determined in accordance with one of the two following formulas:

$$(1) \qquad P = 2S \frac{t}{(D-t)} \; 0.32$$

or

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

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

S = For thermoplastic pipe the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to 23° C (73° F), 38° C (100° F), 49° C (120° F), or 60° C (140° F); for reinforced thermosetting plastic pipe, 75,800 kPa (11,000 psi).

T = Specified wall thickness, mm (in.).

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

SDR = Standard Dimension Ratio = The ratio of average specified outside diameter to minimum specified wall thickness in accordance with a preferred numbering system.

11. Section 192.123 would be amended by revising paragraph (b) to read as follows:

§ 192.123 Design limitations for plastic pipe.

* * * * *

(b) * * *

(1) Below minus 40° C (−40° F); or

(2) Above the following applicable temperatures:

(i) For thermoplastic pipe, the temperature at which the long-term hydrostatic strength used in the design formula under § 192.121 is determined. However, if the pipe was manufactured before May 18, 1978 and its long-term hydrostatic strength was determined at 23° C (73° F), it may be used at temperatures up to 38° C (100° F).

(ii) For reinforced thermosetting plastic pipe, 66° C (150° F).

* * * * *

§ 192.145 [Amended]

12. Section 192.145 would be amended by changing the word "value" to read "valve" in paragraph (l).

13. Section 192.179 would be amended by revising paragraph (a) introductory text to read as follows:

§ 192.179 Transmission line valves.

(a) Unless otherwise approved in writing by the Administrator, upon an operator's demonstrating an equivalent level of safety, each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows:

* * * * *

14. Section 192.203 would be amended by revising paragraph (b)(2) to read as follows:

§ 192.203 Instrument, control, and sampling pipe and components.

* * * * *

(b) * * *

(2) Except for a pressure regulator that can be isolated by other valves from its source of pressure, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

* * * * *

15. Section 192.227 would be amended by revision paragraph (b) and adding paragraph (c) to read as follows:

§ 192.227 Qualification of welders.

* * * * *

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

(c) Except as provided in § 192.229(c), after initial qualification, a welder may not perform welding unless:

(1) Within the preceding 15 calendar months, but at least once each calendar year, the welder has requalified under paragraph (b) of this section; or

(2) Within the preceding 7½ calendar months, but at least twice each calendar year, the welder has had—

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

(ii) For welders who work only on service lines 2 inches or smaller in diameter, two sample welds tested and found acceptable in accordance with the test in section III of appendix C to this part.

16. Section 192.229 would be amended by revising paragraph (c) to read as follows:

§ 192.229 Limitations on welders.

* * * * *

(c) A welder qualified under § 192.227(a) may not weld on pipe to be operated at a pressure that produces a hoop stress at or above 20 percent of SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under section 3 or 6 of API Standard 1104, except that a welder qualified under an earlier edition previously listed in appendix A may weld but my not requalify under that earlier edition.

17. Section 192.241 would be amended by revising paragraph (c) to read as follows:

§ 192.241 Inspection and test of welds.

* * * * *

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 6 of API Standard 1104. The operator may elect to evaluate a girth weld flaw, except a crack, that is unacceptable under section 6 of API Standard 1104, in accordance with the criteria of the appendix (alternative Acceptance Standards for Girth Welds) to API Standard 1104.

18. Section 192.243 would be amended by revising paragraph (d)(4) to read as follows:

§ 192.243 Nondestructive testing.

* * * * *

(d) * * *

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

* * * * *

19. Section 192.281 would be amended by redesignating paragraph (c)(3) as paragraph (c)(4) and adding paragraph (c)(3) to read as follows:

§ 192.281 Plastic pipe.

(c) * * *

(3) An electrofusion joint must be joined utilizing the equipment and techniques expressly prescribed by the fitting manufacturer.

* * * * *

20. Section 192.283 would be amended by revising paragraph (a)(1)(ii) and adding paragraph (a)(1)(iii) to read as follows:

§ 192.283 Plastic pipe; qualifying joining procedures.

(a) * * *

(1) * * *

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517; or

(iii) In the case of electrofusion fittings for polyethylene pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Tests) or paragraph 9.2 (Sustained Pressure Test) or paragraph 9.3 (Tensile Strength Test) or paragraph 9.4 (Joint Crush Test) of ASTM F1055;

* * * * *

21. Section 192.317 would be amended by revising paragraph (a) to read as follows:

§ 192.317 Protection from hazards.

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

* * * * *

22. Section 192.319 would be amended by revising paragraph (c) to read as follows:

§ 192.319 Installation of pipe in a ditch.

* * * * *

(c) All offshore pipe in water at least 12 feet deep but not more than 200 feet deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet of water must be installed so that the top of the pipe is 36 inches below the seabed for normal excavation or 18 inches for rock excavation.

23. Section 192.321 would be amended by revising paragraph (a) and adding paragraph (g) to read as follows:

§ 192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level unless otherwise permitted by paragraph (g) of this section.

* * * * *

(g) Uncased plastic pipe may be temporarily installed above ground level subject to all of the following:

(1) The duration of the installation must not exceed 30 days.

(2) The location of the pipe must be such that it is unlikely to be damaged by external forces, otherwise the pipe must be protected from such damage.

(3) The pipe must have adequate resistance for the exposure to ultraviolet light and for the exposure to high and low temperatures.

(4) The pipe must not be used in subsequent above ground level installations.

24. Section 192.327 would be amended by revising paragraph (e) to read as follows:

§ 192.327 Cover.

* * * * *

(e) All pipe which is installed in a navigable river, stream, or harbor must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock, and all pipe installed in any offshore location under water less than 12 feet deep, as measured from mean low tide, must have a minimum cover of 36 inches in soil or 18 inches in consolidated rock, between the top of the pipe and the natural bottom. However, less than the minimum cover is permitted in accordance with paragraph (c) of this section for pipe other than pipe in the Gulf of Mexico and its inlets.

25. Section 192.455 would be amended by revising paragraphs (a)(2) and (f)(1) to read as follows:

§ 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) * * *

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

* * * * *

(f) * * *

(1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion resistance is provided by the alloy composition; and

* * * * *

26. Section 192.475 would be amended by revising paragraph (c) to read as follows:

§ 192.475 Internal corrosion control: General.

* * * * *

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 standard cubic feet may not be stored in pipe-type or bottle-type holders.

27. Section 192.485 would be amended by adding paragraph (c) to read as follows:

§ 192.485 Remedial measures: Transmission lines.

* * * * *

(c) In paragraphs (a) and (b) of this section, the strength of the pipe based on actual remaining wall thickness may be determined by the procedure in ASME B31G Manual for Determining the Remaining Strength of Corroded Pipelines. Application of the procedure in the B31G Manual shall apply to corroded regions (not penetrating the pipe wall) in existing steel pipelines in accordance with limitations set out in the B31G Manual.

28. Section 192.491 would be revised to read as follows:

§ 192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records and maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) For each test, survey, or inspection required by this subpart, each operator shall maintain a record in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. For each test, survey, or inspection required by §§ 192.465 (a) and (e) and § 192.475(b), records must be retained for as long as the pipeline remains in service. All other records required by this paragraph must be retained for at least 5 years.

29. Section 192.553 would be amended by revising paragraph (d) to read as follows:

§ 192.553 General requirements.

* * * * *

(d) *Limitation on increase of maximum allowable operating pressure.* Except as provided in § 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under this part for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if one or more of the variables necessary to determine the design pressure for the new segment under § 192.619(a)(1) is unknown, the design pressure may be determined by:

(1) Testing the segment in accordance with ASME B31.8, appendix N, to produce a stress equal to the yield strength, and

(2) Applying to not more than 80 percent of the first pressure that produces a yielding the appropriate factors in §§ 192.619(a)(2)(ii) and 192.619(a)(2)(iii).

§ 192.607 [Removed]

30. Section 192.607 would be removed and reserved.

§ 192.611 [Amended]

31. In § 192.611, paragraphs (b) and (c) would be redesignated as paragraphs (c) and (d), paragraph (a)(3)(ii) would be redesignated as paragraph (b), and paragraph (a)(3)(iii) would be redesignated as paragraph (a)(3)(ii) respectively.

32. Section 192.614 would be amended by revising paragraphs (b)(2) introductory text and (c)(2) as follows:

§ 192.614 Damage prevention program.

* * * * *

(b) * * *

(2) Provide for general notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (b)(1) of the following as often as needed to make them aware of the damage prevention program:

* * * * *

(c) * * *

(2) Pipelines in a Class 3 location defined by § 192.5(b)(3)(ii) that are marked in accordance with § 192.707.

* * * * *

33. Section 192.619 would be amended by adding paragraph (a)(2)(iii), and removing paragraphs (a)(4) and (a)(5) and redesignating paragraph (a)(6) as paragraph (a)(4) and revising it.

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) * * *

(2) * * *

(iii) For steel pipe operated at a 100 p.s.i.g. or more, the pressure determined from the table above further reduced by a factor of 0.60 for furnace butt welded pipe and by 0.80 for furnace lap welded pipe.

* * * * *

(4) 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.

* * * * *

34. Section 192.625 would be amended by revising paragraph (f) to read as follows:

§ 192.625 Odorization of gas.

* * * * *

(f) Each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section. Operators of master meter systems may comply with this requirement by:

(1) Receiving written verification from their gas source that gas odorization levels meet the required levels; and

(2) Conducting periodic "sniff" tests, at the outer extremities of the system, to confirm that the gas contains odorant.

35. Section 192.705 would be amended by adding paragraph (c) to read as follows:

§ 192.705 Transmission lines: Patrolling

* * * * *

(c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

36. Section 192.709 would be revised to read as follows:

§ 192.709 Transmission lines: Record keeping.

Each operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for the useful life of the pipe.

(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 1 year.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

37. Section 192.721 would be amended by revising paragraph (b) to read as follows:

§ 192.721 Distribtuion systems: Patrolling.

* * * * *

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

(1) In Class 1 and 2 locations, at intervals not exceeding 7½ months, but at least twice each calendar year; and

(2) In Class 3 and 4 locations, at intervals not exceeding 4½ months, but at least four times each calendar year.

38. Appendix A would be amended by adding paragraph II.B. (12) to read as follows:

Appendix A—Incorporated by Reference

* * * * *

II. * * *

B. * * *

(12) ASTM Specification F1055 "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (F1055–87).

* * * * *

39. Appendix A would be amended by adding paragraphs II.D. (3) and (4) to read as follows:

Appendix A—Incorporated by Reference

* * * * *

II. * * *

D. * * *

(3) ASME B31G "Manual for Determining the Remaining Strength of Corroded Pipelines" (1991).

(4) ASME B31.8 "Gas Transmission and Distribution Piping Systems" (1989 with Addenda A, B, C).

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Issued in Washington, DC on August 21, 1992.

George W. Tenley, Jr.,

Associate Administrator for Pipeline Safety.

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