DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 195

[Docket PS-127; Amdt. 195-52]

RIN 2137-AC27

Regulatory Review: Hazardous Liquid and Carbon Dioxide Pipeline Safety Standards

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

ACTION: Final rule.

SUMMARY: This rulemaking amends miscellaneous hazardous liquid and carbon dioxide pipeline safety standards to provide clarity, eliminate unnecessary or overly burdensome requirements, and foster economic growth. The changes result from the regulatory review RSPA carried out in response to the President's directive of January 28, 1992, on reducing the burden of government regulation. The changes reduce costs in the liquid pipeline industry without compromising safety.

EFFECTIVE DATE: This regulation is effective July 28, 1994. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of July 28, 1994.

FOR FURTHER INFORMATION CONTACT: J. Willock, (202) 366-2392, regarding the subject matter of this final rulemaking, or the Dockets Unit, (202) 366-5046, regarding copies of this final rulemaking or other material that is referenced herein.

SUPPLEMENTARY INFORMATION:

Background

In a January 28, 1992, memorandum, the President wrote to Department and agency heads about the need to reduce the burden imposed by 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. The President recognized that regulations that do not keep pace with new technologies and innovations impose needless costs and impede economic growth.

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 six organizations about the pipeline safety regulations in part 195. Comments were from three regulated pipeline companies, a pipeline trade association, a state pipeline safety agency, and a federal agency. RSPA considered all comments in its review of the regulations, and these comments are available in the docket. Some comments will be considered in future rulemakings. Additionally, RSPA has published a separate rulemaking "Update of Standards Incorporated by Reference" (58 FR 14519; March 18, 1993) which updates the editions of the industry standards that are incorporated in part 195.

On November 27, 1992, RSPA published a Notice of Proposed Rulemaking; NPRM, (57 FR 56304) proposing 18 changes to the regulations based on the comments received from the public and asked for further comments regarding the proposed changes. RSPA received comments from 21 organizations: 15 pipeline companies, 3 pipeline trade associations, 2 environmental organizations, and 1 county government. RSPA considered all comments in preparation of the final rulemaking and the comments are available in the Docket.

Advisory Committee

The Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC), consisting of 15 members, was established by statute to consider the feasibility, reasonableness, and practicability of proposed pipeline regulations. RSPA implemented the committee balloting process by mail. After initial balloting, the process allowed each member to review the ballots, including comments, of all other members, and to change his or her vote or initial comment if desired. Although some THLPSSC members did not vote on every proposed change, a tally of the second ballots showed that a large majority of THLPSSC members found all the proposed changes technically feasible, reasonable, and practicable. Nonetheless, in developing the final regulations, RSPA considered all final THLPSSC votes and comments, including minority positions. The following discussion explains how RSPA treated THLPSSC positions and public comments on the proposed amendments in developing the final rule.

Changes to Part 195 Safety Standards

The following discussion explains the changes to various standards in part 195:

Section 195.1 Applicability.

Offshore production. Part 195 does not apply to pipelines used in offshore production, whether on the Outer Continental Shelf or in state offshore waters. However, this exception is clearly stated in part 195 only for production on the Outer Continental Shelf (§ 195.1(b)(5)). To clarify that all offshore pipelines used in production are outside part 195, RSPA proposed to delete from § 195.1(b)(5) the phrase "on the Outer Continental Shelf".

The 10 THLPSSC members who voted on the proposed amendment to § 195.1(b)(5) all approved the amendment.

In addition, RSPA received comments from three operators and two pipeline-related associations in support of the amendment and no adverse comments. Therefore, § 195.1(b)(5) is amended as proposed in the NPRM.

We also requested comments on whether there is a gap in the regulation of production lines in state offshore waters. Only one commenter responded. This commenter opined that existing state and federal programs adequately regulate production lines in state waters. In Louisiana, the Departments of Natural Resources and Environmental Quality were said to have comprehensive regulations on facility installation, operation, integrity, and removal, and sufficient authority to address any "gap" that is identified. Since the other states with production lines in state waters have similar regulations, RSPA does not believe there is a gap in the regulation of production lines in state waters.

In-plant piping. Part 195 does not apply to pipeline transportation through onshore production, refining, or manufacturing facilities, or storage or in-plant piping systems associated with such facilities (§ 195.1(b)(6)). Because the physical distinction between a regulated pipeline serving a plant and unregulated in-plant piping is unclear, RSPA proposed to add a definition of "in-plant piping system" to § 195.2. The definition proposed was: "*In-plant piping system* means piping that is located on the grounds of a plant and used to transfer hazardous liquid or carbon dioxide between plant facilities or between plant facilities and a pipeline, not including any device and associated piping that are necessary to control pressure in the pipeline." The NPRM explained that we would consider in-plant piping to extend to the plant boundary in the absence of a necessary pressure control device on plant grounds.

All ten THLPSSC members who voted on this proposal supported it. However, four members believed that because the NPRM primarily concerned pipeline transportation rather than production, refining, or manufacturing plants, it did not give plant owners adequate notice that the proposed definition could affect plant piping. These members wanted RSPA to publish a separate NPRM on the subject of in-plant piping.

RSPA does not agree that another NPRM is needed. The subject of in-plant piping and the associated issues were clearly discussed in the published NPRM. Also, all interested persons, including plant owners as well as pipeline operators, were given an opportunity to comment on the subject of in-plant piping.

RSPA received comments on the proposed definition from seven operators, two pipeline-related associations, and one state agency. Two operators and one association fully supported the proposal.

One operator and a pipeline-related association thought plant owners were not adequately notified of the proposed rule, and that RSPA should treat the subject in a separate NPRM. Our position on this issue is given supra in response to a similar criticism by four THLPSSC members.

Another operator was concerned that the proposed definition would cause operator-owned components, such as pipe, meters, instruments, and manifolds, that are located on plant grounds downstream from the operator's pressure control device to fall outside part 195. The operator was worried that other agencies would regulate these components as non-transportation related facilities. We are not persuaded, however, that the potential for such regulation is sufficient reason to exclude the components from the definition of in-plant piping system. The aim of the proposed definition was to distinguish unregulated piping, not to limit the jurisdiction of other government agencies.

In contrast, an operator of gathering and processing facilities was concerned that part 195 would apply to plant piping that lies between any necessary pressure control device and the connection to a pipeline. This commenter apparently did not realize that such piping is subject to part 195. RSPA has applied part 195 to such piping because it is subject to pressure which is controlled by a device operators must have to meet § 195.406(b). However, this application has had little effect on plant owners, because we hold the pipeline operator, not the plant owner, responsible for compliance.

An operator commenting on the plant device exclusion in the proposed definition advised us to change "control pressure" to "prevent overpressure." This commenter said the change would avoid making pipeline operators responsible under part 195 for nonessential pressure control devices. We agree the suggested rewording would better convey the intent of the proposal. But, in the final definition, we have changed "control pressure in the pipeline" to "control pressure in the pipeline under § 195.406(b)" to convey the intent even more precisely.

The state agency commented that if piping on plant grounds does not include a device necessary to control pipeline pressure, the jurisdiction of part 195 over the pipeline should not end at the plant boundary. Instead, the state agency recommended ending jurisdiction at a component inside the plant, such as a flange, where the pipeline can be isolated for purposes of testing. Although operators may use such components, part 195 does not require that they be on the pipeline. Also, we believe the plant boundary is a more convenient demarcation of in-plant piping than an unspecific inside-the-plant component. Thus, the state agency's comment is not incorporated in the final definition.

The state agency, an operator, and a pipeline-related association were concerned that because segments of transfer piping located off plant grounds were not included in the proposed definition, a large number of short pipelines would come under part 195. RSPA recognizes that production, refining, or manufacturing plants often install transfer piping off plant grounds. A plant may use this piping to transfer hazardous liquids between its different facilities located on the same grounds; between its different facilities located on separate grounds (usually separated by a roadway, railway, waterway, or industrial area); between its facilities and a transportation system, such as a railroad or pipeline; or between its facilities and the facilities of another plant or industrial consumer. The three commenters thought the off-grounds segments should qualify as in-plant piping if they connect facilities of the same plant. The association also wanted to include under the definition off-grounds segments that connect facilities of different plants. In addition, the operator and association argued that the off-grounds segments pose minimum risk to public safety and the environment, because the segments generally are located in industrial areas, roadways, or railways. The association further argued that a plant has the same operational control, including response capability, over the off-grounds segments as it does over piping on plant grounds.

In response to these comments, we note that § 195.1(b)(6) echoes section 201(3) of the Hazardous Liquid Pipeline Safety Act of 1979 (HLPSA), (49 U.S.C. app. 2001(3)), which excludes certain "in-plant piping systems" from regulation under the HLPSA. Since neither the HLPSA nor its legislative history explain "in-plant piping," we adopt an ordinary, reasonable understanding of the term. Therefore, we do not accept the interpretation that the term includes piping that crosses the property of others outside plant grounds. However, many plants are separated by a public thoroughfare, and plant transfer piping crosses the thoroughfare. A single public thoroughfare would include any road, from a country lane to an interstate highway, but it does not include a railroad. Because transfer piping that crosses such thoroughfares is comparable in most respects to other in-plant piping, RSPA considers the in-plant piping exception to include the thoroughfare crossings. The thoroughfare exception does not apply to inter-facility lines or delivery lines, because these lines are distinct from in-plant piping. We did not intend the proposed definition of "in-plant piping systems" to expand our present interpretation of the term. So the final definition does not incorporate any of the comments concerning piping located off plant grounds other than for thoroughfare crossings.

However, the proposed definition's first use of the term "pipeline" is changed to "pipeline or other mode of transportation." This change is needed to include, within the definition, piping on plant grounds that transfer hazardous liquid or carbon dioxide between plant facilities and modes of transportation other than pipeline.

Terminal facilities. Part 195 does not apply to the transportation of hazardous liquid or carbon dioxide by vessel, aircraft, tank truck, tank car, or other vehicle, or by terminal facilities used exclusively to transfer hazardous liquid or carbon dioxide between such modes of transportation (§ 195.1(b)(7)). RSPA proposed to amend § 195.1(b)(7) to clarify that terminal facilities located off terminal grounds are subject to part 195, and to distinguish unregulated terminal facilities from a regulated pipeline entering or leaving the terminal. As with the proposed in-plant piping definition, any device and associated piping on terminal grounds necessary to control pressure in a regulated pipeline would not be excepted from part 195.

The THLPSSC voted to approve this proposal, but four members believed the NPRM did not give terminal owners adequate notice that the proposed amendment could affect their piping. These members wanted RSPA to publish a separate NPRM on the subject. For the reasons stated supra in response to a similar argument by these THLPSSC members concerning in-plant piping, RSPA does not agree that another NPRM is needed.

Five operators and two pipeline-related associations commented on the proposed amendment to § 195.1(b)(7). Of these commenters, two operators and one association agreed with the proposal.

A few commenters expressed the same concerns about the proposed amendment to § 195.1(b)(7) as they did about the proposed in-plant piping definition. These concerns were that the NPRM did not adequately notify plant (terminal) owners of the proposed rule, and that some operator-owned components located on plant (terminal) grounds would fall outside part 195. Our response to these concerns is the same as stated supra regarding in-plant piping.

In regard to transfer lines located outside terminal grounds at ports, an operator and a pipeline-related association pointed out that the U.S. Coast Guard regulates transfers between terminal storage and dock facilities. These commenters suggested that RSPA and Coast Guard develop a memorandum of understanding to limit Coast Guard's regulations to dock facilities.

We recognize that Coast Guard and RSPA jurisdictions overlap in port areas, but the two agencies have different responsibilities. Also, the overlap does not automatically result in regulatory conflicts, and the commenters did not mention any. Nonetheless, though we have not changed the final rule as a result of this comment, in enforcing part 195 at port areas, RSPA will act appropriately to resolve any unnecessary regulatory burdens.

Carbon dioxide injection system. Section 195.1(b)(8) provides that part 195 does not apply to "[t]ransportation of carbon dioxide downstream from a point in the vicinity of the well site at which carbon dioxide is delivered to a production facility." RSPA proposed to amend this section to clarify that the exception covers pipelines used in the injection of carbon dioxide for oil recovery operations.

The THLPSSC approved the proposed amendment (10 voted in favor and 5 did not vote), and we received no adverse comments from the public. The proposed amendment to § 195.1(b)(8) is, therefore, adopted as final.

Section 195.2 Definitions.

The proposed revision of the definition of "Secretary" is not adopted in this rulemaking. Instead, it is being handled in an omnibus rulemaking covering all regulations involving pipeline safety.

The definition of "In-plant piping system" is discussed above in § 195.1 Applicability.

Two commenters objected to the proposed definition for petroleum products because of its use of the terms "flammable", "toxic", and "corrosive" which are not defined under part 195. The commenters stated that absent specific definitions for these terms, their applicability could be unclear.

RSPA agrees with the comments about the lack of clarity in the proposed definition for petroleum products. So, the final rule for this section includes new definitions for "flammable", "toxic", and "corrosive" that come from the definitions contained in 49 CFR part 173 for Transportation and Packaging of Hazardous Materials for the terms "flammable liquid", "poisonous material", and "corrosive material", respectively. RSPA has adopted the definition of "poisonous material" for "toxic" because it considers the terms synonymous.

Sections 195.2, 195.106, 195.112, 195.212 and 195.413 (Nominal Outside Diameter of the Pipe in Inches)

RSPA proposed to standardize the dimensioning of pipe size throughout part 195 (Changes are made to §§ 195.2, 195.106(b), 195.106(c), 195.112(c), 195.212(b)(3)(ii) and 195.413(a)). All 10 THLPSSC members who voted were in favor of the proposal and no commenter objected thereto. Accordingly, the proposed amendment is adopted as final.

Section 195.3 Matter incorporated by reference.

Section 195.3 sets out the general requirements for the incorporation in the regulations of industry standards for the design, construction and operation of hazardous liquid and carbon dioxide pipelines. Paragraph 195.3(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. Accordingly, RSPA hereby revises § 195.3(a) to clarify that an entire document is not incorporated when the document is incorporated by reference; rather, only those portions specifically referenced in the regulations are incorporated.

The rule is being revised to conform to a recent update of references in another rulemaking (Update of Standards Incorporated by Reference (58 FR 14519; March 18, 1993)). Also, references to ASME/ANSI Codes B31.8 and B31.G are being added. The 10 THLPSSC members who voted and 7 commenters favored the revision.

Section 195.5 Conversion to service subject to this part.

Section 195.5 regulates the conversion of steel pipelines to hazardous liquid or carbon dioxide service that is subject to part 195. Under § 195.5(a)(4), a converted pipeline must be hydrostatically tested to substantiate the maximum operating pressure (MOP) permitted by § 195.406.[1]

To substantiate the MOP of a converted pipeline, an operator must know the pipe design pressure (see current § 195.406(a)(1)). Consequently, if pipe design pressure is unknown, a steel pipeline may not be converted under § 195.5. Although the design pressure of components is an MOP factor under § 195.406(a)(2), pipeline components are normally designed to be as strong or stronger than attached pipe. Thus, pipe design is the critical factor in substantiating MOP under § 195.5(a)(4), and lack of knowledge of component design pressure is not a significant safety concern.

RSPA proposed to amend § 195.5 to permit conversion using an approach found in section 845.214 and Appendix N of ASME B31.8 for gas pipelines whose design pressure is unknown. Under this proposal, operators would pressure test the pipeline under Appendix N until pipe yield occurs. Instead of design pressure, this yield test pressure would be used to compute MOP by applying certain reduction factors to 80 percent of the first pressure that produces pipe yield.

All THLPSSC members who voted on the proposed amendment to § 195.5

[1] Section 195.5(a)(4) actually uses the term "maximum allowable operating pressure," but for consistency with § 195.406, this term is changed below to MOP by removing the word "allowable."

supported it in concept. However, two members thought the wording of Appendix N should be copied directly into part 195 to avoid referencing a gas pipeline code in liquid pipeline regulations. We believe the principles of Appendix N apply equally to gas and liquid pipelines. And since the B31.8 Code is widely used, operators of hazardous liquid or carbon dioxide pipelines will not find it difficult to obtain and apply Appendix N.

RSPA received five comments on the proposed amendment to § 195.5. Two operators and a pipeline-related association agreed with the proposed amendment.

One operator suggested that if pipelines operating at less than 20 percent of specified minimum yield strength (SMYS) are subject to § 195.5, RSPA should allow operators up to 10 years to meet the testing requirements. At present, none of the standards in part 195, including § 195.5, applies to pipelines operating at less than 20 percent of SMYS (see § 195.1(b)(3)). However, this commenter may have had in mind § 206 of the Pipeline Safety Act of 1992 (Pub. L. 102–508), which provides that exceptions to regulations under the Hazardous Liquid Pipeline Safety Act of 1979 (49 U.S.C. app. 2001 *et seq.*), such as part 195, may not be based solely on low internal stress. Because of this statutory mandate, RSPA has proposed to apply part 195 to certain low-stress hazardous liquid pipelines (Docket PS–117; 58 FR 12213; March 3, 1993). Still, that proposal would not require any existing low-stress hazardous liquid pipeline to be tested under § 195.5, because such pipelines would not be converted pipelines. Of course, if part 195 becomes applicable to low stress pipelines, any pipeline converted to low stress hazardous liquid service subject to part 195 would have to be tested under § 195.5. But, since testing is the backbone of the conversion process, RSPA does not believe § 195.5 should be amended to extend the time for testing to 10 years.

A state agency was concerned that if test pressure must be measured at the high elevation point of test segments, the test could stress the low point of the segment beyond yield. However, the Appendix N test method should not result in overstress at the low elevation, because the method does not require increases in test pressure after the first yield occurs in the test segment.

In a separate rulemaking proceeding (Docket No. PS–124; 57 FR 39572; August 31, 1992), RSPA proposed to allow the use of the Appendix N method in converting pipelines to gas service under 49 CFR 192.14. This gas pipeline conversion standard is similar to § 195.5. Comments to that notice argued that pressure testing to yield is unnecessary to qualify certain pipelines that operate at low stress (generally pipelines 12¾ inches or less in nominal outside diameter operating at pressures of 200 psig or less). RSPA believes these comments are also relevant to hazardous liquid pipelines. All other factors being equal, hazardous liquid pipelines operating at low internal stress present less risk of failure from time-dependent defects than higher stress hazardous liquid pipelines. Because of the lower risk, RSPA has modified the final rule to provide that pipelines 12¾ inches or less in nominal outside diameter to be operated at a pressure of 200 psig or less may be converted without testing to yield. The MOP of such pipelines may be determined under § 195.406 by using 200 psig as pipe design pressure.

The proposed rule has been redrafted to improve clarity, to better relate conversion to design pressure and MOP under § 195.406, and to include the changes discussed supra. In the final rule, the proposed amendment to § 195.5(a)(1) is revised and published as an amendment to § 195.406(a)(1). This latter section deals specifically with pipe design pressure and MOP. As set forth infra, revised § 195.406(a)(1) provides that when pipe design pressure is unknown for steel pipelines being converted, a reduced value of first yield hydrostatic test pressure may be used as design pressure to compute MOP. If the pipeline to be converted is 12¾ inches or less in nominal outside diameter and is not yield tested, 200 psig may be used as design pressure.

Section 195.8 Transportation of hazardous liquid or carbon dioxide in pipelines constructed with other than steel pipe.

The proposal to replace the word "he" with "the Secretary" to remove any implication of gender is not adopted in this rulemaking. Instead, this proposal will be handled in an omnibus rulemaking to make minor clarifications and error corrections covering all the pipeline safety regulations.

Section 195.50 Reporting accidents and § 195.52 Telephonic notice of certain accidents.

Sections 195.50(f) and 195.52(a)(3) require operators to prepare reports and give telephonic notice of accidents, respectively, when the estimated property damage due to an accident exceeds $5,000. RSPA discovered from its regulatory review and previous enforcement cases that a significant amount of confusion exists among pipeline operators as to which cost estimates must be included in calculating the "estimated property damage to the property of the operator or others * * *" Frequently, when reporting accidents, pipeline operators fail to include as "property damage" the fair market value of the product released or those costs associated with clean-up and recovery efforts. RSPA believes these costs should be included when reporting accidents.

Because the $5,000 reporting requirement requires the reporting of minor accidents, RSPA proposed amending §§ 195.50(f) and 195.52(a)(3) to increase the reporting threshold to $50,000, the same level as required in 49 CFR part 192 and to include as property damage the value of the product released and the costs associated with clean-up and recovery efforts. The THLPSSC voted 10 to 0 in favor of the change (5 members did not vote). Two of those favoring the proposed changes recommended that RSPA modify the final rule to limit property damage to fair market value of the lost product and initial clean-up and product recovery costs. One member said that clean-up and recovery costs should not be included in total property damage.

Three commenters disagreed with the proposed changes and recommended that the rule be withdrawn. One complaint was that the statistical base would be discontinuous because, in the future, RSPA would not receive information on accidents costing between $5,000 and $50,000. Another complaint was that the change could affect the development of environmental protection requirements. RSPA understands that a change in reporting levels will cause a slight skewing due to truncation of the data, but believes requiring operators to report accidents based solely on the $5,000 property damage criterion is unnecessary and burdensome. Significant accidents will still be reported because the other criteria (especially those that are environmentally related) requiring reports will be unchanged: (1) Explosion or fire, (2) loss of 50 barrels of liquid, (3) escape of five barrels a day of highly volatile liquids, (4) a death, (5) bodily harm, or (6) resulted in the pollution of any stream. Because these requirements remain unchanged, those operators with more frequent small releases will still be identified. As to a skewing of the data, those organizations that keep track of such statistical data should be able to make adjustments to account for such changes. Also, as explained in the NPRM, this change will make the liquid safety reporting requirements consistent with the gas safety reporting requirements which will eliminate confusion. The rule change should have little, if any, effect on the environment because the same spill volume reporting criteria remain in effect. Only the dollar level of the reporting criterion is being changed.

Two commenters supported the rule changes as they were written. Five others favored the changes, but proposed modification of the rules to explain more fully the meaning of "estimated total damage" in order to spell out the items that must be covered. They said that "estimated total damage" is ambiguous and confusing and subject to interpretation. One commenter stated that the costs of subsurface restoration should be excluded from property damage because it is nearly impossible to estimate the subsurface restoration costs within the time allowed to report the accident.

RSPA agrees that early estimates of the costs to clean-up a liquid spill may not be exact; however, the operator should, at a later date, submit a revised report that provides more reliable cost figures for the clean-up.

RSPA is clarifying the issue by amending § 195.50(f) to read: "(f) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000" and § 195.52(a)(3) to read: "(3) Caused estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000."

Section 195.106 Internal design pressure.

Section 195.106(a) prescribes the formula for calculating the design pressure of steel pipe. In addition, § 195.106(b) regulates the pipe yield strength used in the design pressure formula. When the specified minimum yield strength (SMYS) of pipe is unknown, § 195.106(b) requires that yield strength be derived from tensile tests on random samples of pipe. Based on a comparable gas pipeline safety standard (49 CFR 192.107(b)(2)), RSPA proposed to amend § 195.106(b) to allow operators to use 24,000 psi as yield strength if pipe of unknown SMYS is not tensile tested. Editing changes to § 195.106(b) were also proposed.

The 10 THLPSSC members who voted on the proposed amendment of § 195.106(b) supported it (5 did not vote). In addition, RSPA received comments from four operators and one pipeline-related association. The association and three of the operators agreed with the proposal. One of these operators suggested further editing, part of which RSPA has included in the final rule.

One operator was concerned that the proposed rule could unjustifiably reduce the MOP of its pipelines. The operator said its pipelines are made of Grade B pipe (yield strength at least 35,000 psi) or better. However, some pipelines may contain pipe for which documentation of yield strength or tensile testing does not exist. For such pipe, without new tensile testing, yield strength would have to be assumed to be 24,000 psi. The operator suggested that RSPA allow operators to use appropriate evidence besides tensile tests to demonstrate the yield strength of pipe.

In response to this comment, we note, first, that the proposed amendment to § 195.106(b) would not affect the design pressure of existing pipelines unless they are replaced, relocated, or otherwise changed (see § 195.100). Second, § 195.106(b) currently requires operators to use as yield strength either SMYS or a value based on tensile testing. So the operator's apparent difficulty in verifying yield strength is a problem of compliance with the current rule. Third, the proposed rule would relax the burden of tensile testing only when MOP does not exceed the level that corresponds to a yield strength of 24,000 psi. When a higher MOP is desired, operators must use the tensile testing option. Finally, RSPA is not aware of any acceptable evidence of the yield strength of pipe of unknown SMYS apart from appropriate tensile testing. Thus, the amendments to § 195.106(b), as discussed above, are adopted.

Section 195.204 Inspection-general.

The THLPSSC voted 10 to 0 in favor of the proposed change to make the language gender neutral and, except for a minor correction, no objections were received from commenters. The proposed change is adopted as corrected.

Section 195.228 Welds; standards of acceptability.

One of the comments we received on proposed amendments to nondestructive testing requirements under § 195.234(e) (discussed infra) concerned the standards for acceptance of weld flaws (§ 195.228(b)). A pipeline-related association asked us to incorporate by reference the alternative acceptance standards for girth welds that are in the Appendix to American Petroleum Institute (API) Standard 1104 (17th edition). For weld acceptability, § 195.228(b) now references the standards in Section 6 of API Standard 1104.

In a notice of proposed rulemaking involving our review of the gas pipeline safety standards in 49 CFR part 192 (Docket PS–124; 57 FR 39572; August 31, 1992), RSPA proposed to allow gas operators to apply the API appendix in addition to section 6 criteria. Although that proposal was based on a petition by API to incorporate the appendix by reference in both parts 192 and 195, we overlooked the request to include such a proposal in the present rulemaking.

In the part 192 rulemaking, RSPA's gas pipeline safety advisory committee voted to support the proposed amendment. Also, all but one of the public comments were in favor of allowing use of the Appendix of API Standard 1104.

The dissenting commenter was concerned that industry inspection personnel may not be qualified to apply the appendix. However, this commenter may not have recognized that under §§ 192.243(b) and (c), operators must ensure that nondestructive testing is performed in accordance with written procedures by persons who have been properly trained and qualified. Sections 195.234(b) and (c) provide similar requirements for nondestructive testing of welds on hazardous liquid and carbon dioxide pipelines. RSPA believes these requirements are adequate to assure proper application of the appendix.

The Appendix of API Standard 1104 applies equally to girth welds in gas and liquid pipelines. This amendment is not mandatory, rather it provides pipeline operators an optional operating procedure. In view of the prior opportunity for public comment on use of the appendix for gas pipelines, the favorable response by public commenters and RSPA's advisory committee, and the fact that use of the appendix would not be mandatory, we believe that a further opportunity for public comment is unnecessary to allow use of the appendix under § 195.228(b). We feel this amendment is a logical outgrowth of the Notice and furthers our efforts to make parts 192 and 195 consistent wherever possible. This amendment will not have a substantial impact on the regulated community.

Thus, in accordance with 5 U.S.C. 553(b)(3)(B), we are amending § 195.228(b) to reference the appendix without further rulemaking notice. However, should any person be adversely affected by this decision or wish to change the final rule, that person may submit a petition for reconsideration under RSPA's rulemaking procedures in 49 CFR 106.35.

The final rule provides that the appendix may be used only for girth welds to which the appendix applies. For example, as section A.1 of the appendix states, neither welds in pump stations nor welds used to connect fittings and valves are covered by the appendix. Also, the appendix applies only to girth welds between pipe of equal nominal wall thickness.

Section 195.234 Welds: Nondestructive testing.

Section 195.234(e) requires that "100 percent of each day's girth welds installed in * * * [certain] locations must be nondestructively tested 100 percent unless impracticable, in which case at least 90 percent must be tested." RSPA proposed to amend § 195.234(e) to clarify that "90 percent" pertains to the number of girth welds that must be tested over their entire circumference.

In addition, § 195.234(g) requires: "At pipeline tie-ins 100 percent of the girth welds must be nondestructively tested." RSPA proposed to clarify that this standard applies to tie-ins of replacement sections of pipeline.

The THLPSSC supported the proposed amendments, although one member thought part 195 should define the word "impracticable." We did not adopt this recommendation because the word is used in its ordinary dictionary sense.

Three operators and two pipeline-related associations commented on the proposed amendments. Three commenters agreed with the proposal, one suggested editing changes, and one made a related proposal discussed supra under the heading, "§ 195.228(b) Welds; standards of acceptability." Although we did not adopt all the editing suggestions, these comments helped us provide clarity to the final rule.

In addition, one commenter thought the proposed amendment of § 195.234(g) was unnecessary because § 195.200 already indicates that § 195.234(g) applies to replacement sections. Moreover, the commenter thought adding the proposed phrase to § 195.234(g) would create confusion over whether §§ 195.234(a) through (f) apply to replacement sections. While these observations have theoretical merit, in practice, some operators have failed to recognize that "pipeline tie-ins" include tie-ins of replacement sections. The clarifying phrase adds emphasis where it is apparently needed to assure compliance with the full extent of the rule. Section 195.234(g) is, therefore, adopted as proposed.

Sections 195.246 Installation of pipe in a ditch and 195.248 Cover over buried pipeline.

Section 195.246(b) is inconsistent with § 195.413(b)(3) for pipe in the Gulf of Mexico and its inlets (See § 195.2 Definitions) under water less than 15 feet deep but at least 12 feet deep, because § 195.246(b) 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 § 195.2, and must have the minimum cover required by § 195.413(b)(3). In addition, §§ 195.248(a) and (b) are inconsistent with § 195.413(b)(3) for pipe in the Gulf of Mexico and its inlets under water less than 12 feet deep. Section 195.248(a) allows pipe to be less than 12 inches below the seabed (i.e., a hazard to navigation). In certain instances, § 195.248(b) allows pipe to be without cover or less than 12 inches below the seabed. Neither condition is allowed under § 195.413(b)(3). In light of these inconsistences, RSPA proposed in the NPRM to amend §§ 195.246(b) and 195.248(a) and (b) to correct the problem.

Ten THLPSSC members favored the proposed changes (5 members did not vote). One of the members favoring the changes said it would make more sense to retain the existing regulation which operators have adhered to for years. In similar manner, two commenters and one pipeline-related organization agreed with the proposal. One commenter and two pipeline-related organizations disagreed and suggested that references to a depth of 15 feet in the rule be eliminated. RSPA proposed changes to §§ 195.246(b), 195.248(a) and 195.248(b) so these sections would conform with Public Law 101-599 (section 1, 104 Stat. 3038 (1990)) which requires burial of pipe where the subsurface is under 15 feet of water as measured from mean low water. Therefore, §§ 195.246(b), 195.248(a) and 195.248(b) are adopted as proposed in the NPRM.

Section 195.262 Pumping equipment.

Section 195.262(d) regulates the location of pumping equipment. The rule prohibits the installation of pumping equipment on property not under the operator's control. It also prohibits installation less than 50 feet from the pump station boundary. RSPA proposed to amend § 195.262(d) to clarify that these two restraints on location apply conjunctively not alternatively.

The THLPSSC members who voted on the proposed amendment supported it in concept, but 5 members recommended further editing of the rule for clarity. Although three of the five persons who commented on the proposal supported it as proposed, the other two commenters thought further clarifying changes were needed. In view of these comments and THLPSSC views, we have modified the final rule based on identical wording suggested by five THLPSSC members and one commenter.

Section 195.304 Testing of components.

Section 195.304(b) excludes from hydrostatic testing under part 195 any component that is the only item being replaced or added to a pipeline system if the component or a prototype was tested at the factory. RSPA proposed to amend § 195.304(b) to clarify that the excluded components do not include pipe.

The THLPSSC fully supported the proposed amendment. Of the six comments from the public on the proposal, a pipeline-related association and two operators agreed with it, while three operators suggested changes.

An operator suggested that instead of amending § 195.304(b), we should revise the definition of "component" to exclude pipe. We did not adopt this suggestion because the revision would affect every rule in part 195 that uses the term "component." Editing suggested by another operator was not adopted because it concerned matters not addressed in the NPRM.

One operator felt pipe should be excluded from hydrostatic testing under § 195.304(b) to the same extent as other components. The operator said that hydrostatically testing short sections of mill tested pipe is duplicative, costly, and not needed for safety. Although the NPRM did not propose to alter the existing requirement that replacement sections of pipe of any length must be hydrostatically tested to part 195 standards before operation, we do not agree with this commenter's contention. Normal pipe mill tests are not duplicative of part 195 tests, and are not a proven safe alternative to part 195 requirements. However, for short sections of replacement pipe, part 195 test requirements could be met anywhere, including, by prior arrangement with the operator, in the pipe mill. So if an operator wishes to avoid field testing of short replacement sections of pipe, it only needs to assure that the mill tests of those sections were done in accordance with part 195 test requirements.

Section 195.406 Maximum operating pressure.

The changes to § 195.406 are discussed supra under § 195.5.

Section 195.412 Inspection of rights-of-way and crossings under navigable waters.

Section 195.412(a) requires an operator, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, to inspect the surface conditions on or adjacent to each pipeline right-of-way. Because some surface condition activities that affect the safety and operation of pipelines are more visible from aerial patrols than from walking or driving the right-of-way, RSPA proposed that the section be changed to clarify that aerial patrols are an optional method of compliance. No comments were received regarding the change and the THLPSSC voted 10 to 0 in favor of the change (5 members did not vote). Accordingly, the change to § 195.412(a) is adopted as proposed.

Section (b) requires operators, at intervals not exceeding 5 years, to inspect each crossing under a navigable waterway (except offshore) to determine the condition of the crossing. The purpose of the inspection is to look for any damage, unanticipated loading, or loss of protection that could threaten the safety of the pipeline. We stated in the NPRM that bored crossings are usually so deep that there is little likelihood the pipeline could be affected by waterway-related events, such as scouring or anchor dragging. We proposed to add an exception to § 195.412(b) to cover bored crossings that are too deep to be subject to waterway-related damage.

The THLPSSC voted 10 to 0 in favor of the rule (5 members did not vote). However, a state pipeline agency suggested the existing regulation be retained. The agency stated that a pipeline operator cannot be 100 percent sure a bored crossing is so deep it cannot be affected as stated. RSPA received four additional comments, three of which expressed an opinion that the phrase "too deep to anticipate damage from waterway conditions or vessel traffic" is vague and inappropriate. The other commenter said the proposal is unduly restrictive and should be refocused from bored crossings to a more generic performance standard potentially including all crossings.

In view of the comments received, RSPA agrees with those who opined that "too deep to anticipate damage from waterway conditions or vessel traffic" is too vague. In the absence of a recognized standard on the subject, it is too speculative to judge when bored crossings are buried at a sufficient depth to be safe from damage by external forces. Therefore, it is in the interest of public safety that the current rule requiring inspection at intervals not exceeding 5 years be retained. Accordingly, the proposed change to § 195.412(b) is not adopted.

Section 195.416 External Corrosion Control.

Section 195.416(a) states that each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, conduct tests on each underground facility that is under cathodic protection to determine whether protection is adequate. RSPA is clarifying the rule to reduce any misunderstanding regarding what is meant by "underground." The word "underground" in this paragraph has meant any facility that is buried or in contact with the ground. This rule clarification will not change the burden on operators because RSPA compliance inspectors have consistently required any facility in contact with the ground to be cathodically protected.

RSPA received two comments regarding the change to § 195.416(a). One commenter recommended that offshore pipelines be excluded from annual testing requirements. RSPA believes there is no acceptable substitute for regular testing to determine if corrosion protection of all lines, both onshore and offshore, is adequate. Accordingly, "in contact with the ground or submerged" is added to the rule to assure that all underwater pipelines, both onshore and offshore, are included in the definition. The other commenter suggested requiring the testing of "carrier pipes" in casings. "Carrier pipes" are normally buried and subject to the rule. The THLPSSC voted 10 to 0 in favor of the proposed change (5 members did not vote). The revision to § 195.416(a) is adopted as modified.

Section 195.416(f) requires that any pipe found to be generally corroded so that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances must either be replaced with coated pipe that meets the requirements of part 195 or, if the area is small, must be repaired. However, the operator need not replace generally corroded pipe if the operating pressure is reduced to be commensurate with the limits on operating pressure specified in § 195.406, based on the actual remaining wall thickness.

Section 195.416(g) states that if localized corrosion pitting is found to exist to a degree where leakage might result, the pipe 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 (f) and (g) do not provide guidance for an operator's use in determining the strength of the actual remaining wall thickness of corroded steel pipe. To provide such guidance, RSPA proposed amending § 195.416(h) to adopt the ASME Manual B31G procedure for determining the remaining strength of corroded steel pipe in existing pipelines. Application of the procedure was proposed to be in accordance with the limitations set out in the B31G Manual. The rule would provide guidance as to whether a corroded region (not penetrating the pipe wall) may be left in service; this option might require a reduction in maximum allowable operating pressure, but may be more economical than replacement or repair of the corroded pipe.

Ten THLPSSC members voted for the proposal (5 members did not vote).

Comments relative to § 195.416(h) were received from five commenters. One commenter said the proposal to change § 195.416(h) is inappropriate and should be redone to be consistent with § 192.485. Others stated that the proposal was unnecessarily restrictive because it did not allow the use of other proven industry developed methods for determining the remaining strength of corroded pipelines. The most noteworthy method mentioned was "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk)" developed by Battelle under the Pipeline Research Committee of the American Gas Association (AGA). (Project PR 3–805, December 1989, AGA catalog No. L51609). Project PR 3–805 was undertaken to devise a modified criterion that, while still assuring pipeline integrity, would eliminate as much as possible the excessive specifications embodied in the ASME B31G manual. The AGA modified criterion, using a complex analysis approach, can be carried out by means of a PC-based program called RSTRENG. The modified criterion can also be applied via tables or curves or a long-hand equation if a simplified analysis is preferred.

The addition of the modified criterion to the rule does not compromise safety because it merely accepts an established pipeline industry guideline, and does not impose new requirements on the operators. Accordingly, RSPA is amending § 195.416(h) to include the AGA/Battelle—A Modified Criterion for

Evaluating the Remaining Strength of Corroded Pipe (with the computer disk RSTRENG).

Rulemaking Analyses

Impact Assessment

This final rule is not considered a significant regulatory action under section 3(f) of Executive Order 12866 and, therefore, was not subject to review by the Office of Management and Budget. The rule is not considered significant under the regulatory policies and procedures of the Department of Transportation (44 FR 11034).

A Regulatory Evaluation has been prepared and is available in the docket. RSPA estimates the proposed changes to existing rules would result in an estimated savings of $1,534,000 per year for the hazardous liquid pipeline industry at no cost to the industry, 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 and operating pipelines, and the elimination of unnecessary requirements.

Federalism Assessment

RSPA has analyzed the proposed rules under the criteria of Executive Order 12612 (52 FR 41685; October 30, 1987). The regulations have no substantial effects on the states, on the current federal-state relationship, or on the current distribution of power and responsibilities among the various levels of government. Thus, preparation of a federalism assessment is not warranted.

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. 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 have a significant economic impact on a substantial number of small entities. This rule applies to intrastate and interstate pipeline facilities used in the transportation of hazardous liquids or carbon dioxide.

Paperwork Reduction Act

The documentation for the information collection requirements for part 195 was submitted to the Office of Management and Budget (OMB) during the original rulemaking processes. Currently, regulations in part 195 are covered by OMB Control Numbers 2137–0047 (approved through May 31, 1994), 2137–0578 (approved through October 31, 1994) and 2137–0583 (approved through May 31, 1994). There are no new information collection requirements in this final rule.

List of Subjects in 49 CFR Part 195

Ammonia, Carbon dioxide, Incorporation by reference, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, RSPA is amending 49 CFR part 195 as follows:

PART 195—[AMENDED]

1. The authority citation for part 195 continues to read as follows:

Authority: 49 app. U.S.C. 2002 and 2015; and 49 CFR 1.53.

2. In § 195.1, the introductory text of paragraph (b) is republished, paragraph (b)(5) is revised, in paragraph (b)(6) a hyphen is added between the words "in" and "plant", and paragraphs (b)(7) and (b)(8) are revised to read as follows:

§ 195.1 Applicability.

* * * * *

(b) This part does not apply to—

* * * * *

(5) Transportation of hazardous liquid or carbon dioxide in offshore pipelines which are located upstream from the outlet flange of each facility where hydrocarbons or carbon dioxide are produced or where produced hydrocarbons or carbon dioxide are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

* * * * *

(7) Transportation of hazardous liquid or carbon dioxide—

(i) By vessel, aircraft, tank truck, tank car, or other non-pipeline mode of transportation; or

(ii) Through facilities located on the grounds of a materials transportation terminal that are used exclusively to transfer hazardous liquid or carbon dioxide between non-pipeline modes of transportation or between a non-pipeline mode and a pipeline, not including any device and associated piping that are necessary to control pressure in the pipeline under § 195.406(b); and

(8) Transportation of carbon dioxide downstream from the following point, as applicable:

(i) The inlet of a compressor used in the injection of carbon dioxide for oil recovery operations, or the point where recycled carbon dioxide enters the injection system, whichever is farther upstream; or

(ii) The connection of the first branch pipeline in the production field that transports carbon dioxide to injection wells or to headers or manifolds from which pipelines branch to injection wells.

* * * * *

3. In § 195.2, the introductory text is republished, definitions for Corrosive product, Flammable product, In-plant piping system, Petroleum, Petroleum product, and Toxic product are added in alphabetical order to read as follows:

§ 195.2 Definitions.

As used in this part—

* * * * *

Corrosive product means "corrosive material" as defined by § 173.136 Class 8–Definitions of this chapter.

* * * * *

Flammable product means "flammable liquid" as defined by § 173.120 Class 3–Definitions of this chapter.

* * * * *

In-plant piping system means piping that is located on the grounds of a plant and used to transfer hazardous liquid or carbon dioxide between plant facilities or between plant facilities and a pipeline or other mode of transportation, not including any device and associated piping that are necessary to control pressure in the pipeline under § 195.406(b).

* * * * *

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

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

* * * * *

Toxic product means "poisonous material" as defined by § 173.132 Class 6, Division 6.1–Definitions of this chapter.

§§ 195.2, 195.112, 195.212, 195.413 [Amended]

4. In the list below, for each section indicated in the left column, the phrase indicated in the middle column is removed and the phrase indicated in the right column is added:

Section	Remove	Add
195.2, *Gathering line*	8 inches or less in nominal diameter	219.1 mm (8⅝ in) or less nominal outside diameter.
195.112(c)	An outside diameter of 4 inches or more	A nominal outside diameter of 114.3 mm (4½ in) or more.
195.212(b)(3)(ii)	The pipe is 12 inches or less in outside diameter.	The pipe is 323.8 mm (12¾ in) or less nominal outside diameter.
195.413(a)	Except for gathering lines of 4-inch nominal diameter or smaller.	Except for gathering lines of 114.3 mm (4½ in) nominal outside diameter or smaller.

5. In § 195.3, paragraph (a) is revised to read as follows:

§ 195.3 Matter incorporated by reference.

(a) Any document or portion thereof incorporated by reference in this part is included in this part as though it were printed in full. When only a portion of a document is referenced, then this part incorporates only that referenced portion of the document and the remainder is not incorporated. Applicable editions are listed in paragraph (c) of this section in parentheses following the title of the referenced material. Earlier editions listed in previous editions of this section may be used for components manufactured, designed, or installed in accordance with those earlier editions at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR for a listing of the earlier editions.

* * * * *

6. In § 195.3, paragraphs (b)(1) through (b)(5) are redesignated as paragraphs (b)(2) through (b)(6) and paragraph (b)(1) is added to read as follows:

§ 195.3 Matter incorporated by reference.

* * * * *

(b) * * *

(1) American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.

* * * * *

7. In § 195.3, paragraphs (c)(2)(iii) and (c)(2)(iv) are redesignated as paragraphs (c)(2)(v) and (c)(2)(vi) and paragraphs (c)(2)(iii) and (c)(2)(iv) are added to read as follows:

§ 195.3 Matter incorporated by reference.

* * * * *

(c) * * *

(2) * * *

(iii) ASME/ANSI B31.8 "Gas Transmission and Distribution Piping Systems" (1989 with ASME/ANSI B31.8a–1990, B31.8b–1990, B31.8c–1992 Addenda and Special Errata issued July 6, 1990 and Special Errata (Second) issued February 28, 1991).

(iv) ASME/ANSI B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines" (1991).

* * * * *

8. In § 195.3, paragraphs (c)(1) through (c)(4) are redesignated as paragraphs (c)(2) through (c)(5) and paragraph (c)(1) is added to read as follows:

§ 195.3 Matter incorporated by reference.

* * * * *

(c) * * *

(1) American Gas Association (AGA): AGA Pipeline Research Committee, Project PR–3–805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989). The RSTRENG program may be used for calculating remaining strength.

* * * * *

9. Section 195.5 is amended by revising paragraphs (a)(1) and (a)(4) to read as follows:

§ 195.5 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 necessary to verify the design pressure under § 195.106 or to perform the testing under paragraph (a)(4) of this section is unknown, the design pressure may be verified and the maximum operating pressure determined by—

(i) Testing the pipeline in accordance with ASME B31.8, 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 design factor F in § 195.106(a) and the appropriate factors in § 195.106(e).

* * * * *

(4) The pipeline must be tested in accordance with subpart E of this part to substantiate the maximum operating pressure permitted by § 195.406.

* * * * *

10. Section 195.50(f) is revised to read as follows:

§ 195.50 Reporting accidents.

* * * * *

(f) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.

11. Section 195.52(a)(3) is revised to read as follows:

§ 195.52 Telephonic notice of certain accidents.

(a) * * *

(3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000;

* * * * *

12. Section 195.106(b) is revised to read as follows:

§ 195.106 Internal design pressure.

* * * * *

(b) The yield strength to be used in determining the internal design pressure under paragraph (a) of this section is the specified minimum yield strength. If the specified minimum yield strength is not known, the yield strength to be used in the design formula is one of the following:

(1)(i) The yield strength determined by performing all of the tensile tests of API Specification 5L on randomly selected specimens with the following number of tests:

Pipe size	No. of tests
Less than 168.3 mm (6⅝ in) nominal outside diameter.	One test for each 200 lengths.
168.3 through 323.8 mm (6⅝ through 12¾ in) nominal outside diameter.	One test for each 100 lengths.
Larger than 323.8 mm (12¾ in) nominal outside diameter.	One test for each 50 lengths.

(ii) If the average yield-tensile ratio exceeds 0.85, the yield strength shall be taken as 165,474 kPa (24,000 psi). If the average yield-tensile ratio is 0.85 or less, the yield strength of the pipe is taken as the lower of the following:

(A) Eighty percent of the average yield strength determined by the tensile tests.

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

(2) If the pipe is not tensile tested as provided in paragraph (b) of this section, the yield strength shall be taken as 165,474 kPa (24,000 psi).

* * * * *

13. In § 195.106(c), the last sentence is revised to read as follows:

§ 195.106 Internal design pressure.

* * * * *

(c) * * * However, the nominal wall thickness may not be more than 1.14 times the smallest measurement taken on pipe that is less than 508 mm (20 in) nominal outside diameter, nor more than 1.11 times the smallest measurement taken on pipe that is 508 mm (20 in) or more in nominal outside diameter.

* * * * *

14. In § 195.204, the last sentence is revised to read as follows:

§ 195.204 Inspection—general.

* * * No person may be used to perform inspections unless that person has been trained and is qualified in the phase of construction to be inspected.

15. Section 195.228(b) is revised to read as follows:

§ 195.228 Welds and welding inspection: Standards of acceptability.

* * * * *

(b) The acceptability of a weld is determined according to the standards in section 6 of API Standard 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix to API Standard 1104 applies to the weld, the acceptability of the weld may be determined under that appendix.

16. Section 195.234 is amended by revising the introductory text of paragraph (e) and by revising paragraph (g) to read as follows:

§ 195.234 Welds: Nondestructive testing.

* * * * *

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

* * * * *

(g) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent of the girth welds must be nondestructively tested.

17. Section 195.246 is amended by revising paragraph (b) to read as follows:

§ 195.246 Installation of pipe in a ditch.

* * * * *

(b) Except for pipe in the Gulf of Mexico and its inlets, all offshore pipe in water at least 3.7 m 12-ft-deep but not more than 61 m (200 ft) 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.

18. Section 195.248 is amended by revising in the first column of the table in paragraph (a) the language "Other offshore areas under water less than 12-ft-deep as measured from the mean low tide" to read "Gulf of Mexico and its inlets and other offshore areas under water less than 12-ft-deep as measured from the mean low tide" and by revising the introductory text of paragraph (b) to read as follows:

§ 195.248 Cover over buried pipeline.

* * * * *

(b) Except for the Gulf of Mexico and its inlets, less cover than the minimum required by paragraph (a) of this section and § 195.210 may be used if—

* * * * *

19. Section 195.262(d) is revised to read as follows:

§ 195.262 Pumping equipment.

* * * * *

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

* * * * *

20. The introductory text of § 195.304(b) is revised to read as follows:

§ 195.304 Testing of components.

* * * * *

(b) A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either—

* * * * *

21. Section 195.406 is amended by republishing the introductory text of paragraph (a) and revising paragraph (a)(1) to read as follows:

§ 195.406 Maximum operating pressure.

(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:

(1) The internal design pressure of the pipe determined in accordance with § 195.106. However, for steel pipe in pipelines being converted under § 195.5, if one or more factors of the design formula (§ 195.106) are unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factors in §§ 195.106 (a) and (e); or

(ii) If the pipe is 323.8 mm (12¾ in) or less outside diameter and is not tested to yield under this paragraph, 1379 kPa (200 psig).

* * * * *

22. Section 195.412(a) is revised to read as follows:

§ 195.412 Inspection of rights-of-way and crossings under navigable waters.

(a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate means of traversing the right-of-way.

* * * * *

23. Section 195.416 is amended by revising paragraph (a), redesignating paragraph (h) as paragraph (i) and adding a new paragraph (h) to read as follows:

§ 195.416 External corrosion control.

(a) Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, conduct tests on each buried, in contact with the ground, or submerged pipeline facility in its pipeline system that is under cathodic protection to determine whether the protection is adequate.

* * * * *

(h) The strength of the pipe, based on actual remaining wall thickness, for paragraphs (f) and (g) of this section may be determined by the procedure in ASME B31G manual for Determining the Remaining Strength of Corroded Pipelines or by the procedure developed by AGA/Battelle—A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk). Application of the procedure in the ASME B31G manual or the AGA/Battelle Modified Criterion is applicable to corroded regions (not penetrating the pipe wall) in existing steel pipelines in accordance with limitations set out in the respective procedures.

* * * * *

Issued in Washington, DC, on June 9, 1994.

Ana Sol Gutiérrez,

Acting Administrator, Research and Special Programs Administration.

[FR Doc. 94–15510 Filed 6–27–94; 8:45 am]

BILLING CODE 4910–60–P