the general financial disclosures necessary to establish that the small business is in fact small. The estimated time for filling out an FCC Form 175 is 45 minutes. Each applicant will have to submit information regarding the ownership of the applicant, any joint venture arrangements or bidding consortia that the applicant has entered into, and, if claiming eligibility for bidding credits, financial information demonstrating that the applicant qualifies as a small business. Applicants that do not have audited financial statements available will be permitted to certify the validity of their financial showings. While many small businesses have chosen to employ attorneys prior to filing an application to participate in an auction, the rules are intended to enable a small business to file an application on its own using the short form application preparation guidelines that are made available by the Commission before any auction. When an applicant wins a license, it will be required to submit an FCC Form 601 license application, which will require technical information regarding the applicant's proposals for providing service and other information. This application will require information provided by an engineer who will have knowledge of the system's design. The estimated time for completing an FCC Form 601 is one hour and fifteen minutes.

E. Significant Alternatives Minimizing the Economic Impact on Small Entities

16. The RFA requires an agency to describe any significant alternatives that it has considered in reaching its proposed approach, which may include the following four alternatives: (1) The establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities; (2) the clarification, consolidation, or simplification of compliance or reporting requirements under the rule for small entities; (3) the use of performance, rather than design, standards; and (4) an exemption from coverage of the rule, or any part thereof, for small entities.

17. In the 3rd FNPRM, the Commission proposes that the part 1 unjust enrichment provisions will govern partitioning and disaggregation arrangements involving AMTS licenses owned by small businesses that were afforded a bidding credit and later elect to partition or disaggregate their licenses to an entity that does not qualify as a small business. The alternative to applying the unjust enrichment provisions would be to allow an entity who had benefited from the special bidding provisions for small businesses to become unjustly enriched by partitioning or disaggregating its licenses to parties that do not qualify for such benefits.

18. The 3rd FNPRM solicits comment on a variety of alternatives set forth herein. Any significant alternative presented in the comments will be considered.

F. Federal Rules that May Duplicate, Overlap, or Conflict With the Proposed Rules

None.

List of Subjects 47 CFR Parts 13 and 80

Communications equipment, Radio.

Federal Communications Commission.

Magalie Roman Salas,

Secretary.

[FR Doc. 00–31309 Filed 12–7–00; 8:45 am]

BILLING CODE 6712–01–U

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 195

[Docket No. RSPA–97–2762; Notice 3]

RIN 2137–AD24

Controlling Corrosion on Hazardous Liquid and Carbon Dioxide Pipelines

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

ACTION: Notice of proposed rulemaking.

SUMMARY: We are proposing to change some of the corrosion control standards for hazardous liquid and carbon dioxide pipelines. The proposed changes are based on our review of the adequacy of the present standards compared to similar standards for gas pipelines and acceptable safety practices. The proposed changes are intended to improve the clarity and effectiveness of the present standards and reduce the potential for pipeline accidents due to corrosion.

DATES: Persons interested in submitting written comments on the proposed rules must do so by February 6, 2001. Late filed comments will be considered so far as practicable.

ADDRESSES: You may submit written comments by mailing or delivering an original and two copies to the Dockets Facility, U.S. Department of Transportation, Room PL–401, 400 Seventh Street, SW., Washington, DC 20590–0001. The Dockets Facility is open from 10:00 a.m. to 5:00 p.m., Monday through Friday, except on Federal holidays when the facility is closed. Or you may submit written comments to the docket electronically at the following web address: *http://dms.dot.gov.* See the **SUPPLEMENTARY INFORMATION** section for additional filing information.

FOR FURTHER INFORMATION CONTACT: L. M. Furrow by phone at 202–366–4559, by fax at 202–366–4566, by mail at U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590, or by e-mail at *buck.furrow@rspa.dot.gov.*

SUPPLEMENTARY INFORMATION:

Filing Information, Electronic Access, and General Program Information

All written comments should identify the docket and notice numbers stated in the heading of this notice. Anyone who wants confirmation of mailed comments must include a self-addressed stamped postcard. To file written comments electronically, after logging onto http://dms.dot.gov, click on ''Electronic Submission.'' You can read comments and other material in the docket at this Web address: http://dms.dot.gov. General information about our pipeline safety program is available at this address: http://ops.dot.gov.

Background

We have reviewed the corrosion control standards in 49 CFR part 195 for hazardous liquid and carbon dioxide pipelines to see if any standards need to be made clearer, more effective, or consistent with acceptable safety practices. Although the likelihood of corrosion-caused accidents harming people or the environment is relatively low, we undertook the review because corrosion is the second leading cause of reported accidents on hazardous liquid pipelines, and improving the standards has the potential to reduce the number of future accidents.[1]

The review began September 8, 1997, when we held a public meeting on how the part 195 corrosion control standards and the corrosion control standards for gas pipelines in 49 CFR part 192 might be improved (62 FR 44436; Aug. 21, 1997). To attract participation by corrosion experts, we held the public meeting in Oakbrook, Illinois, in conjunction with meetings of NACE International, a professional technical society dedicated to corrosion control.

[1] For the period 1986 through 1999, corrosion caused 25 percent of all incidents reported under Part 195; 3 percent of all deaths; 2 percent of all injuries; and 19 percent of all property damage.

The Oakbrook meeting focused on whether we should incorporate by reference NACE Standard RP0169–96, ''Control of External Corrosion on Underground or Submerged Metallic Piping Systems,'' as a substitute for all or some of the part 192 and part 195 standards. Two other significant topics were whether part 192 and part 195 corrosion control standards need to be updated to ensure safety, and whether gas, hazardous liquid, and carbon dioxide pipelines should be subject to the same corrosion control standards.

For technical and other reasons, including the document's non-mandatory style, most meeting participants and subsequent commenters opposed incorporating the entire NACE Standard RP0169–96 by reference. But participants agreed universally that part 192 and part 195 corrosion control standards are largely sufficient, and although some changes may be needed, the standards should be generally the same.

Toward this end, we began to consider whether the more comprehensive part 192 standards, possibly with some changes, would be appropriate for hazardous liquid and carbon dioxide pipelines. For technical input, we met from time to time with representatives of NACE, the pipeline industry, and state pipeline safety agencies. At these meetings, we also examined whether the part 192 standards need to be more effective or clearer. As guidance for this assessment, the meeting participants developed the following principles:

- Evaluate existing data and use the evaluation to assess the need to change standards.
- Continue to improve public safety and environmental protection.
- Assess the need for corrosion control standards throughout the national pipeline system based on the risk associated with different parts of the system.
- Upgrade regulations to allow for future changes in pipeline industry technology and operating practices as appropriate.
- Strive for uniform interpretation/enforcement.
- To the extent practicable, involve all interested parties in assessing the need to change standards.
- Use the new cost/benefit policy framework being developed for RSPA's pipeline safety advisory committees in determining the costs and benefits of potential changes to standards.
- Achieve balance between performance and prescriptive language.
- Develop performance measures to assess the effectiveness of corrosion control programs.
- Focus on managing corrosion to maintain pipeline integrity.
- Provide adequate regulatory flexibility to allow operators to implement alternative measures that meet the performance requirements of the corrosion regulations.

The meetings left us with various concerns about the total effectiveness and clarity of the part 192 corrosion control standards and the suitability of applying those standards to hazardous liquid and carbon dioxide pipelines. We also knew that the National Association of Pipeline Safety Representatives (NAPSR), the Gas Piping Technology Committee (GPTC), and the National Transportation Safety Board (NTSB) had at various times recommended changes to part 192 and part 195 corrosion control standards. So, to get public comment on our concerns and the recommended changes, we held another public meeting on April 28, 1999, in San Antonio, Texas (64 FR 16885; April 7, 1999). We also invited comments on the idea of allowing operators to follow their own corrosion management plans or NACE Standard RP0169–96 as an alternative to all or part of the part 192 or part 195 corrosion control standards.

San Antonio Meeting

At least 180 persons attended the San Antonio public meeting. However, only a few persons made oral statements, which are summarized as follows:

The Interstate Natural Gas Association of America (INGAA) said that based on the record of low numbers of deaths and injuries, not much change in the part 192 standards is needed, even if corrosion is the second leading cause of reported pipeline incidents. INGAA attributed the good safety record to proper management of risk, saying it would be nonproductive if changes to generally applicable safety standards caused operators to shift their limited resources away from higher risk areas. INGAA emphasized the use of cost/benefit assessment in determining the need for new or revised standards. At least two other meeting participants (Enron and Columbia Gulf) expressed support for INGAA's views.

The American Gas Association (AGA) and American Public Gas Association (APGA) jointly made a statement similar to INGAA's and pointed out that DOT safety statistics do not justify changes in the present standards. AGA/APGA further noted that corrosion is not the second leading cause of incidents on gas distribution lines, but the last cause, resulting in about 4 percent of all reported incidents. The views of AGA/APGA were supported by at least one other meeting participant (Columbia Gulf) and by a majority of the persons who submitted written comments to the docket after the meeting. These subsequent written comments are condensed below under the ''Comments after San Antonio'' subheading.

Another participant, Global Cathodic Protection, submitted a statement, backed by 72 corrosion control practitioners, that cathodic protection criteria in appendix D of part 192 are preferred to the criteria in NACE Standard RP0169–96.

Equilon Enterprises, an operator of petroleum pipelines, did not support the alternative of corrosion management plans, because of the burden of review by government and the possibility that government reviewers and operator personnel may not be equally qualified to evaluate the plans. In addition, Equilon said that removing unnecessary differences between part 192 and part 195 standards would minimize confusion and disagreements between operators and government inspectors. On other points raised in the meeting notice, Equilon preferred that part 195 not refer to NACE Standard RP0169–96. But, Equilon did support the need for qualification requirements for bosses who lead corrosion control programs, and it thought the part 192 standards should disallow the use of bare unprotected pipe.

An engineering consultant said the ''instant-off'' approach to measuring cathodic protection was excessive. Similarly, the Equilon representative said that across-the-board use of the negative 850 mV criterion with instant-off readings is not productive, and that the 100 mV criterion is more cost-effective in many cases. A university professor said that corrosion control technicians do not do instant-off tests the same way. But another engineering consultant noted that NACE has a companion standard that covers instant-off tests: TM0497–97, Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems.

Comments Submitted After the San Antonio Meeting

Following the San Antonio public meeting, the docket remained open to receive written comments on the matters addressed in the meeting notice. Sixty-two persons filed written comments. These commenters included pipeline safety agencies in Arizona and Iowa, two corrosion control firms (Corrosion Control International and Global Cathodic Protection), two operators of petroleum pipelines (Mobil Corporation and Tosco Refining Company), seven pipeline trade associations (American Gas Association (AGA), American Public Gas Association (APGA), Interstate Natural Gas Association of America, New England Gas Association, New York Gas Group, Ohio Gas Association, and American Petroleum Institute), six operators of interstate gas pipelines (CMS Energy, Columbia Energy Group, Duke Energy, Enron Gas Pipeline Group, KN Energy, and Phillips Pipe Line Company), and 43 local gas distribution companies.

General Comments. Most of the written comments specifically address RSPA concerns and other topics in the San Antonio meeting notice. Still, there were some general comments: Two gas distribution operators said that requiring operators to cathodically protect cast iron or ductile iron pipe would have a big impact on the distribution industry. These operators also suggested that small fittings made of copper or brass and steel fittings with a corrosion resistant coating should be exempt from cathodic protection requirements. Other rule changes they suggested were intended to yield savings by specifying that electronic or remote data collection can be used to meet the monitoring requirements and by extending the interval for monitoring rectifiers from every 2 months to twice a year, particularly for newly manufactured devices.

AGA/APGA welcomed minor rule changes that address clarity, consistency, technology, but said that sweeping changes are not justified by the safety data. They advised us to use cost/benefit assessment and non-regulatory approaches to perceived problems. Of the 62 commenters, 42 expressed support for the joint comments of AGA/APGA. Others, such as Mobil Corporation, Enron, and the New England Gas Association, similarly expressed doubt that substantial changes to the standards were warranted in view of the incident record. One commenter, Kansas Gas Service, backed up its claim that the present standards are adequate by referring to its own record: no reported incidents for the period 1989–98. Tosco Refining stated that making the corrosion control maintenance requirements in Parts 192 and 195 alike would mitigate compliance difficulties for companies that operate both gas and petroleum pipelines.

Comments on RSPA Concerns: This section of the preamble includes summaries of comments that specifically address RSPA's concerns about whether certain provisions of Part 192 corrosion control standards need to be improved. The AGA/APGA comments are identified because many commenters supported the AGA/APGA views. Summaries of comments on changes recommended by NAPSR, GPTC, and NTSB, on alternatives, and on topics included in the ''Public Participation'' section of the meeting notice are discussed afterward.

Section 192.453 Personnel Qualification

RSPA Concern: In view of the proposed rules on qualification of pipeline personnel (63 FR 57269; Oct. 27, 1998) [2], are more specific qualification standards needed for individuals who direct or carry out corrosion control procedures?

Comments: All 23 comments on this concern opposed changing § 192.453. They said either the existing rule is adequate or the proposed rules on personnel qualification are sufficient. Most of these commenters also opposed establishing specific technical qualifications for company managers. They said these personnel need more business than technical knowledge to assure that corrosion and other maintenance problems are handled economically. AGA/APGA suggested that any remaining qualification issues be addressed in a non-regulatory way through ongoing discussions with industry training representatives at DOT's Transportation Safety Institute.

Section 192.455 External Corrosion: New Pipelines

RSPA Concern: Should a cathodic protection system be installed on offshore pipelines in less than one year after the pipeline is constructed, for example, 60 days, because of the strong corrosiveness of salt water?

Comments: The two comments on this concern favored a 60-day installation period.

RSPA Concern: Is it in the interest of safety to exempt pipelines in particular environments and temporary pipelines from the coating and cathodic protection requirements?

Comments: Three commenters opposed the present exemptions, either because corrosion leaks can happen rapidly or because the installations are so varied they should be handled by waivers rather than general exemption. At the same time, three commenters supported the exemptions, contending that corrosion is usually a long term problem, many environments are not conducive to corrosion, and required monitoring would detect incipient problems. AGA/APGA said that safety data do not suggest the present exemptions have been detrimental to safety.

Section 192.457 External Corrosion: Existing Pipelines

RSPA Concern: Should existing compressor, regulator, and measuring station piping continue to be excluded from the requirement to cathodically protect effectively coated transmission line pipe?

Comments: Five commenters said the piping should not be excluded, arguing that it does not differ from pipe that must be protected and that failures at these locations may have serious consequences. Three other commenters said they cathodically protect all their compressor, regulator, and measuring station piping.

RSPA Concern: Is the present requirement to cathodically protect certain older existing pipelines only in areas of ''active corrosion'' adequate for public safety? If not, what would be a cost-effective alternative standard?

Comments: Only one commenter opposed the present rule. This commenter contended that the entire pipeline needs protection because spot protection moves the corrosion problem to other places on the line. However, 13 commenters, including AGA/APGA, supported the present rule, saying that it is a cost-effective approach to protecting older lines, particularly since not all corrosion is detrimental to safety. Another commenter thought that adding cathodic protection to old bare lines in mildly corrosive or non-corrosive soils could accelerate the rate of any localized corrosion that might exist.

RSPA Concern: Is the meaning of ''active corrosion'' clear and technically sound? If not, how should it be changed?

Comments: None of the 12 comments advocated changing the present definition of ''active corrosion.'' Five commenters, including AGA/APGA, thought that possible changes would be more prescriptive, less flexible, or not appropriate for all areas.

Section 192.461 External Corrosion: Coating

RSPA Concern: Should the implicit requirement to coat field joints and repairs be expressly stated?

Comments: Four commenters said this requirement should be expressly stated. But four other commenters worried that singling out any item would raise questions about items not listed.

[2] After the San Antonio meeting, RSPA adopted final rules on personnel qualification that closely paralleled the proposed rule (64 FR 46853; Aug. 27, 1999).

Similarly, another commenter thought the implicit requirement was adequate for field joints.

RSPA Concern: Does coating need to be compatible with the anticipated service conditions, including the effects of temperature?

Comments: Four commenters agreed that such service compatibility is necessary. And one of these commenters suggested that a performance standard would improve the effectiveness of the existing rule in this regard. However, another commenter said the existing rule is adequate because service compatibility is implied.

RSPA Concern: For offshore pipelines, during installation, are special measures necessary to protect against damage to coating, including field joint coating; and, to avoid mechanical damage, are special coatings needed on J-tubes, I-tubes and pipelines installed by the bottom tow method?

Comments: There were no comments on this concern.

Section 192.463 External Corrosion: Cathodic Protection Criteria

RSPA Concern: Are the cathodic protection system criteria in appendix D of part 192, 300 mV shift and E-log-I, obsolete, since they are not in section 6 of NACE Standard RP0169–96? If so, should operators be allowed to continue to use them on existing pipe, but not new pipe?

Comments: Three commenters favored dropping these two criteria or at least E-log-I from appendix D. Six other commenters said they would support dropping the criteria only if the criteria were known to be ineffective or no longer in use. One commenter acknowledged using E-log-I and two others said the two criteria are adequate and should be allowed. AGA/APGA and one other commenter said the NACE standard recognizes the use of other successful criteria, such as those in appendix D, and that safety data do not show that the 300 mV shift and E-log-I criteria result in higher leak rates or incidents.

Section 192.465 External Corrosion: Monitoring

RSPA Concern: Does the sampling basis prescribed for inspecting short sections of mains or transmission lines not in excess of 100 feet and separately protected service lines provide effective corrosion control, particularly as it applies to service lines that supply gas to public buildings?

Comments: Two commenters thought the present rule is ineffective, asserting that a single inspection is not enough to assess safety over a 10-year period, no matter if public buildings are involved. However, four commenters argued that because corrosion is slow, there has been no problem in sampling pipe to detect corrosion before it becomes critical. And two commenters said sampling is a cost-effective way to monitor scattered sites. AGA/APGA and two other commenters said that safety data do not show that sampled pipe has more corrosion-caused leaks than other pipe. Several commenters foresaw difficulties in defining a ''public building.'' Only one commenter thought that more frequent monitoring is needed for lines leading to public buildings because of the increased potential for serious consequences.

Section 192.467 External Corrosion: Electrical Isolation

RSPA Concern: What remedial action is needed when an electrical short in a casing results in inadequate cathodic protection of the pipeline outside the casing?

Comments: Five commenters said these shorts should be cleared because other options are ineffective and imposing more current to offset the short could have adverse effects. But two other commenters said that clearing shorts can be costly if the line must be taken out of service or replaced, and that there is no consensus on adequate remediation. Another observation by one commenter was that the electrical isolation requirements are not needed since cathodic protection has to meet the criteria for adequacy.

RSPA Concern: Should newly constructed offshore pipelines be electrically isolated from bare steel platforms unless both are protected as a single unit?

Comments: The lone commenter who addressed this concern said that isolation is needed, yet concluded that a rule change was not needed because annual surveys will identify any problem.

RSPA Concern: Is electrical isolation needed where contact with aboveground structures would adversely affect cathodic protection?

Comments: One commenter said we should require isolation in all such cases. Three commenters argued that while isolation is needed a rule change is not, because annual surveys will identify any problem. Three other commenters argued that isolation is not needed if the alternative of sufficient local protection is applied.

Section 192.471 External Corrosion: Test Leads

RSPA Concern: Are accessible test leads needed on offshore risers that are electrically isolated and not accessible for testing?

Comments: The two commenters who addressed this concern said the present rule is adequate because operators must demonstrate adequate cathodic protection, which necessitates test leads.

RSPA Concern: For aluminum pipelines, should all test leads be insulated aluminum conductors and installed to avoid harm to the pipe?

Comments: There were two comments on this concern. One said test leads and connection material must be compatible with aluminum. The other said test leads must be insulated aluminum conductors and installed to avoid harm to the pipe.

Section 192.473 External Corrosion: Interference Currents

RSPA Concern: Where light rail systems exist, should operators specifically be required to identify and test for stray currents and keep records of the test results?

Comments: Four commenters said such a specific requirement was needed for light rail. But three commenters disagreed, arguing the present rule is adequate because it requires operators to test for all sources of stray current, including large junk yard magnets and electric cranes.

Section 192.475 Internal Corrosion

RSPA Concern: Are special requirements needed to deal with the problem of internal corrosion in storage field piping, as evidenced by piping leaks in West Virginia and several Midwestern states?

Comments: Three commenters felt the present rule is adequate for all situations and specific requirements for storage fields are not needed. In contrast, one commenter thought the rule should specifically recognize the problems posed by such piping and require more coupons or traps where liquid might collect, pipe design that avoids liquid collection, use of lined pipe, periodic pigging, or dehydration. Another commenter thought operators should have to prepare a procedure and follow it to minimize internal corrosion.

Section 192.479 Atmospheric Corrosion: General

RSPA Concern: Should new and existing pipelines be subject to the same protection requirements?

Comments: One commenter saw no need to change the distinction between new and existing pipelines.[3] Six others

[3] For new aboveground pipelines, protection is required everywhere the pipeline is exposed to the

Continued

supported treating all aboveground pipelines alike regardless of age, but two of these commenters said the rule should apply only to ''active corrosion,'' not to all corrosion.

RSPA Concern: Is protection needed where corrosion is a light surface oxide or where corrosion will not likely affect the safe operation of the pipeline before the next scheduled inspection?

Comments: Six commenters thought the rule should be changed to exclude surface oxide because it does not affect pipe integrity. However, one commenter thought surface oxide indicates a coating problem that operators should identify and track through continuing surveillance. One other commenter said that even if corrosion is more than superficial, if there is no question of safety before the next inspection, then there is no present need for remedial action. Another commenter recommended limiting the rule to ''active corrosion'' to exclude both superficial corrosion and corrosion that would not likely advance to an unacceptable stage before the next inspection.

RSPA Concern: Is special protection needed in the splash zone of offshore pipelines and at soil to air interfaces of onshore pipelines?

Comments: Three of the four comments on this concern thought the existing corrosion rules for buried and aboveground protection are adequate. The fourth commenter said any need for special protection would be recognized during required inspections.

Section 192.481 Atmospheric Corrosion: Monitoring

RSPA Concern: Should the inspection interval for onshore pipelines be extended beyond 3 years in view of the generally low incidence of serious problems on protected pipelines?

Comments: Two commenters said the present 3-year monitoring cycle is not too burdensome. In contrast, seven commenters recommended extending the inspection period beyond 3 years, saying that atmospheric corrosion is a long-term process. Six of these commenters recommended inspection every 5 years, an interval coincident with the interval of gas leakage surveys. One other commenter suggested the rule let operators determine what inspection intervals are appropriate for the pipelines involved.

RSPA Concern: For onshore pipelines, are more frequent inspections needed at soil-to-air interfaces, under thermal insulation, at disbonded coatings, and at pipe supports?

Comments: The consensus of the four comments on this concern was that no more frequent inspections than annual are needed at these locations. Two commenters said the corrosion problem at these locations is too site-specific for a general inspection rule requiring removal of coating or jackets.

RSPA Concern: For offshore pipelines, are more frequent inspections needed under poorly bonded coatings and at splash zones, support clamps, and deck penetrations?

Comments: There were no comments on this concern.

Section 192.491 Records

RSPA Concern: Should operators keep records of findings of non-corrosive conditions if

Section 192.455 Is Changed To Remove the Benefit of Such Findings?

Comments: Two commenters agreed that if records of non-corrosive conditions no longer have a purpose, the recordkeeping requirement should be removed. But another commenter thought records of exposed pipe inspections under § 192.459 should be kept even if no corrosion is found. This commenter thought such records would be useful in surveillance under § 192.613 and in evaluating the significance of damaged pipe or coating.

RSPA Concern: Is the period for keeping corrosion control monitoring records, ''as long as the pipeline remains in service,'' necessary for safety or accident investigation? If not, what is an appropriate period?

Comments: One commenter believed the present retention period is needed to provide a very helpful general history of pipelines. But another commenter said that old records are never used once adverse conditions are corrected. Two commenters suggested the retention period could be reduced to 5 years or two inspection cycles, whichever is longer. A similar comment was 5 years or the next inspection cycle, whichever is longer.

Recommendations To Change Standards

National Association of Pipeline Safety Representatives

Recommendation: With regard to §§ 192.457 and 192.465, NAPSR recommended changes to clarify the meaning of an ''electrical survey'' and where alternatives to electrical surveys may be used.

Comments: Three commenters reported that the State-Industry Regulatory Review Committee (SIRRC) had reached a consensus on ''electrical survey'' and alternatives. SIRRC was formed by NAPSR and industry representatives to work out differences of opinion over NAPSR's 1992 recommendations to revise part 192.[4] In a report transmitted to RSPA by a letter dated May 3, 1999, SIRRC concludes that electrical surveys are seldom used on distribution systems, so there is no advantage to requiring electrical surveys as a preferred corrosion inspection method on distribution systems. SIRRC further concludes that if electrical surveys are not used, all available information should be used to determine if active corrosion exists. Set out below are SIRRC's suggested revisions of § 192.457(b)(3) and § 192.465(e). SIRRC also said that in the suggested revision, ''pipeline environment'' refers to whether soil resistivity is high or low, wet or dry, contains contaminants that may promote corrosion, or has any other known condition that might influence the probability of active corrosion.

[192.457(b)(3)] Bare or coated distribution lines. The operator shall determine the areas of active corrosion by electrical survey or by analysis and review of the pipeline condition. Analysis and review shall include, but is not limited to, leak repair history, exposed pipe condition reports, and the pipeline environment. For the purpose of this section, an electrical survey is a series of closely spaced pipe-to-soil readings over a pipeline which are subsequently analyzed to identify any locations where a corrosive current is leaving the pipe.

[192.465(e)] (i) For transmission pipelines, after the initial evaluation required by paragraphs (b) and (c) of § 192.455 and paragraph (b) of § 192.457, each operator shall, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey, or where an electrical survey is impractical, by analysis and review of the pipeline condition. Analysis and review shall include, but is not limited to, leak repair history, exposed pipe condition reports, and the pipeline environment.

(ii) For distribution pipelines, after the initial evaluation required by paragraphs (b) and (c) of § 192.455 and paragraph (b) of § 192.457, each operator shall, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey or by analysis and review of

atmosphere, unless the operator can demonstrate that a corrosive atmosphere does not exist. For old pipelines, protection is required only where harmful corrosion is found.

[4] NAPSR's recommendations were published in Notice 2 of Docket No. PS–124 (58 FR 59431; Nov. 9, 1993).

the pipeline condition. Analysis and review shall include, but is not limited to, leak repair history, exposed pipe condition reports, and the pipeline environment.

(iii) For the purpose of this section, an electrical survey is a series of closely spaced pipe-to-soil readings over a pipeline which are subsequently analyzed to identify any locations where a corrosive current is leaving the pipe.

Recommendation: With regard to § 192.459, NAPSR recommended we require operators to record the condition of protective coatings whenever they inspect exposed portions of buried pipeline, arguing the records would provide a useful history of the condition of the pipelines as well as evidence that exposed pipe had been inspected as required.

Comments: Three commenters reported that SIRRC reached a consensus on recording the condition of coating when inspecting exposed pipe. SIRRC said that coating condition is important in evaluating the overall condition of a pipeline, and that this information helps meet continuing surveillance and active corrosion rules. SIRRC's suggested revision of § 192.459 follows:

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined to determine the condition of the coating, or if the pipeline is bare or the coating is deteriorated, the exterior condition of the pipe. A record of the examination results shall be made in accordance with § 192.491(c). If external corrosion is found, remedial action must be taken to the extent required by § 192.483 and the applicable paragraphs of §§ 192.485, 192.487, or 192.489.

Recommendation: With regard to § 192.467(d), NAPSR recommended changes that would require operators to test pipeline casings annually for electrical isolation, and to clarify what must be done to minimize pipeline corrosion if isolation is not achieved.

Comments: Three commenters reported that SIRRC did not agree on whether shorted casings are a problem or on the need to test casings, but agreed that § 192.483 should be amended to include options for dealing with shorted casings. SIRRC said its suggested options are consistent with common industry practice. SIRRC also recognized that the options were not intended as a substitute for proper cathodic protection of pipe under § 192.463. SIRRC's suggested revision of § 192.483 follows:

(d) If it is determined that a casing is electrically shorted to a pipeline, the operator shall: (1) clear the short, if practical; (2) fill the casing with a corrosion inhibiting material; (3) monitor for leakage with leak detection equipment at least once each calendar year at intervals not exceeding 15 months; or (4) conduct an initial inspection with an internal inspection device capable of detecting external corrosion in a cased pipeline, and repeat at least every 5 years at intervals not to exceed 63 months.

Recommendation: With regard to § 192.479(b), NAPSR recommended that regardless of the date of installation, all aboveground pipelines or portions of a pipeline that are exposed to the atmosphere be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion, unless the pipeline is in a non-corrosive atmosphere.

Comments: Two commenters reported that SIRRC reached a consensus that all aboveground pipe should be subject to the same protection requirement. SIRRC's suggested revision of § 192.479, which would remove the present distinction between pipelines installed before and after particular dates, is set forth below. SIRRC also explained that the term ''active corrosion'' does not include non-damaging corrosive films.

[192.479] (a) Each aboveground pipeline or portion of a pipeline that is exposed to the atmosphere must be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph, if the operator can demonstrate by test, investigation, or experience in the area of application that active corrosion does not exist.

(b) If active corrosion is found on an aboveground pipeline or portion of pipeline, the operator shall (1) take prompt remedial action consistent with the severity of the corrosion to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and (2) clean and either coat or jacket the areas of atmospheric corrosion with a material suitable for the prevention of atmospheric corrosion.

Recommendation: With regard to the provision in § 192.487(a) that permits general corrosion in distribution line pipe to be repaired instead of replaced, NAPSR recommended that the provision refer to generally accepted guidelines for determining what corroded areas may be repaired.

Comments: Two commenters reported that SIRRC did not address this issue. In addition, these commenters suggested we allow operators to assess the serviceability of distribution line pipe that has wall thickness less than 30 percent of nominal wall thickness instead of requiring the replacement of such pipe.

Recommendation: With regard to § 192.489(b), NAPSR recommended that we clarify that internal sealing is not an appropriate method of strengthening graphitized pipe.

Comments: Two commenters reported that SIRRC agreed to drop this recommendation, since advances in technology may produce strength enhancing liners.

Gas Piping Technology Committee

The following recommendations are from an April 1995, rulemaking petition by GPTC:

Recommendation: Remove from § 192.467 the requirement that pipe be electrically isolated from metallic casings. GPTC argued there are no safety benefits from clearing shorted casings.

Comments: There were no comments on this recommendation. But see the comments above on § 192.467.

Recommendation: Amend §§ 192.465 and 192.481 to allow operators to take up to 39 months to carry out inspections of unprotected pipelines that must be done at 3-year intervals. GPTC said the extra time would add flexibility to the standards, with no reduction in safety.

Comments: The one comment on this recommendation supported the 39-month period but preferred a 5-year interval to match the interval of leakage surveys. Also, see the comments above on §§ 192.465 and 192.481.

National Transportation Safety Board

As a result of a 1996 accident on a butane pipeline operated by Koch Pipeline Company near Lively, Texas, NTSB recommended two changes to the Part 195 corrosion control standards:

Recommendation: Revise Part 195 to require pipeline operators to determine the condition of pipeline coating whenever pipe is exposed and, if degradation is found, to evaluate the coating condition of the pipeline. (P–98–35)

Comments: There were no comments on this recommendation. But see the SIRRC comment above on § 192.459.

Recommendation: Revise Part 195 to include performance measures for the adequate cathodic protection of liquid pipelines. (P–98–36)

Comment: The only comment favored adding to Part 195 either Appendix D or NACE cathodic protection criteria.

Alternatives

In the San Antonio meeting notice, we suggested two alternatives to the present corrosion control standards: corrosion management plans and NACE Standard RP0169–96. Many operators get excellent results by applying pipeline-specific plans that contain corrosion control methods and management techniques not required by Part 192 or Part 195 standards. NACE Standard

RP0169–96 is widely accepted as the most authoritative source of up-to-date pipeline corrosion control practices.

Comments: Two commenters favored corrosion management plans, saying they would be consistent with the risk-based approach to regulation and cost-effective, since many operators already use them. They also said that to qualify a pipeline for exemption from the standards, the plans should be designed to produce equal or better results than the standards. However, another commenter opposed the plan alternative, arguing that the review and evaluation process would further dilute government and industry resources and detract from higher priority safety matters. And the American Petroleum Institute opposed the plan alternative, saying that corrosion should be treated as part of an overall integrity management plan that may be developed after the conclusion of RSPA's risk management demonstration projects.

Topics 4 and 6 under the next heading drew additional comments on the alternatives.

Topics of Particular Interest

1. Whether any existing standards deter or disallow the use of new technologies, and, if so, how.

Comments: The two comments on this topic were that while none of the standards disallows the use of new technology, unclear standards may deter such use.

2. The costs and benefits of any suggested changes to standards and alternatives to standards.

Comments: The only comment was that we should apply cost/benefit analysis to any suggested changes.

3. The amount of time operators may need to prepare for compliance with any suggested standards or alternatives.

Comments: The only comment was that the time needed for compliance depends on the suggested rule change.

4. With regard to the corrosion management plan and NACE Standard alternatives—

a. The bases for evaluating the adequacy of corrosion management plans.

Comments: Two commenters said the primary basis should be whether corrosion is mitigated by the plan. AGA/APGA and another commenter suggested we defer further consideration of the plan alternative until completion of work by the State/Industry/DOT Regulatory Alternative Feasibility Team, which is considering risk-based alternatives to safety standards.

b. The best way to facilitate agency review of operator decisions under the alternatives (*e.g.*, prior notification, reporting, recordkeeping).

Comments: Both comments on this topic were that we should review the decisions the same as we review decisions in operators' operating and maintenance plans.

c. Whether NACE Standard RP0169–96 is adequate for pipeline corrosion control and, if so, should we incorporate it by reference in our corrosion control standards?

Comments: Only one commenter thought NACE Standard RP0169–96 would be a cost-effective alternative to existing corrosion control standards. Although another commenter said it would be all right to reference NACE Standard RP0169–96, the commenter also said it would be better to use it as a basis for changing the standards. Ten other commenters opposed using NACE Standard RP0169–96. Of these, two said the document is not adequate by itself, and it would complicate the standards if only parts were referenced. AGA/APGA and two other commenters said NACE Standard RP0169–96 is too conservative and too costly to apply, but AGA/APGA and another two commenters thought it could serve as guidance for corrosion management plans. The reason given by one commenter for opposing NACE Standard RP0169–96 was that it does not distinguish non-hazardous corrosion from corrosion detrimental to public safety.

5. For hazardous liquid pipelines—

a. Whether additional standards are needed to further reduce the possibility of damage to environmentally sensitive areas.

Comments: One commenter thought Part 195 should cross reference Appendix D or NACE RP0169 criteria for cathodic protection.

b. If Part 192 standards were applied to hazardous liquid pipelines, the changes, if any, that would be needed to account for differences between gas and liquid pipelines.

Comments: There were no comments on this topic.

6. For gas distribution systems—

a. Root causes of corrosion leaks on coated, uncoated, protected, and unprotected metallic lines.

Comments: AGA/APGA and one other commenter said that corrosion leaks on distribution lines have a low probability of resulting in reportable incidents. Three additional commenters said that corrosion leaks on properly protected pipe are rare, and that most corrosion leaks occur on unprotected bare steel that is too costly to protect. These commenters contended the best approach to combating corrosion leaks is through aggressive leak surveys.

b. Descriptions of operating/maintenance practices to minimize corrosion leaks on cathodically unprotected lines.

Comments: Six commenters reported the use of a ranking system to prioritize segments of bare steel pipe for replacement, based on age, location, leaks, size, and cathodic protection. Other practices included replacement rather than repair of bare steel, and not uprating or reconnecting cast iron, ductile iron, or bare steel pipe. Another commenter said its practices are designed to enhance economic value rather than just meet Part 192 requirements.

c. Descriptions of risk-based corrosion management programs.

Comments: The only commenter said a plan should preserve the intent of the code but allow for geography and operating condition differences.

d. The best approach to monitoring corrosion control in urban wall-to-wall paved areas.

Comments: One commenter suggested taking readings at test stations no further than one block (660 feet) apart, while another advised 1200 feet apart. Still another commenter stressed the importance of creating access openings.

7. The amount of buried piping at compressor, regulator, and measuring stations that is not cathodically protected.

Comments: Three commenters said all their piping in these locations is protected. AGA/APGA said the data are not available, but the piping poses a low risk.

8. Explicit examples of adequate compliance with particular standards that have had varied interpretations.

Comments: AGA/APGA reported that while government compliance personnel interpret some standards inconsistently, the safety statistics support adequate compliance.

9. To provide an acceptable level of safety on existing pipelines, must cathodic protection preserve the pipeline indefinitely or merely slow the rate of corrosion until the pipeline has to be rehabilitated or replaced?

Comments: Two commenters said the decision should be based on a cost/benefit assessment, considering the possible use of new materials and the future need to move or replace a pipeline due to construction by others. One other comment was that corrosion can only be mitigated and to try to do otherwise would be too expensive.

Proposed Subpart H—Corrosion Control

In view of the above concerns, recommendations, and comments, we are proposing to add to part 195 a new subpart H called Corrosion Control. Subpart H would prescribe corrosion control standards for new and existing steel pipelines to which Part 195 applies. Concerns, recommendations, and comments that pertain primarily to the corrosion control standards in Part 192 will be addressed in a future rulemaking proceeding on gas pipelines.

Because commenters showed little enthusiasm for the alternatives of NACE Standard RP0169–96 and corrosion management plans, we did not include either alternative in proposed Subpart H (except as provided in proposed § 195.567 regarding cathodic protection criteria). Nevertheless, because NACE Standard RP0169–96 is so widely respected, we would like to keep the floor open for further discussion of the merits of adopting it as an overall corrosion control standard for pipelines. In this regard, we invite interested persons to comment again on the pros and cons of referencing the entire NACE Standard RP0169–96 as an alternative to proposed Subpart H. This request for comment is not a rulemaking proposal. We recognize that a further notice of proposed rulemaking would be required before the entire NACE Standard RP0169–96 could be incorporated by reference as a Part 195 safety standard.

Proposed Subpart H includes many standards that are identical to present corrosion control requirements in Part 195 and standards that are substantially like present requirements in Part 192. The proposed subpart also includes standards that, while based on present Part 192 requirements, include changes we think are beneficial improvements, considering acceptable safety practices. We do not intend that proposed subpart H results in a lessening of current requirements. Each of the sections in proposed Subpart H is discussed below.

Section 195.551 Scope.

Proposed § 195.551 characterizes the activities that are covered by the proposed standards in subpart H (i.e., protecting steel pipelines against external, internal, and atmospheric corrosion). Section 195.551 is informational in nature and would not impose any obligations.

Like the present corrosion control standards in part 195 (§§ 195.236, 195.238, 195.242, 195.244, 195.414, 195.416, and 195.418), proposed Subpart H would apply only to steel pipelines. In contrast, comparable corrosion control standards for gas pipelines (subpart I of Part 192) apply to pipelines made of any metal. However, because hazardous liquid and carbon dioxide pipelines are made of steel almost exclusively, such broad coverage is not warranted for pipelines regulated by part 195.

Nevertheless, under § 195.8, operators must give us an opportunity to review the safety of any pipeline that is to be constructed with a material other than steel. In the case of a non-steel metallic pipeline, that review would include the operator's plans for corrosion control.

You should note that ''breakout tanks'' [5] come within the scope of proposed subpart H, because part 195 defines ''pipeline'' to include breakout tanks (§ 195.2). Consistent with the convention stated in § 195.1(c), proposed subpart H standards applicable to breakout tanks include standards that concern breakout tanks specifically and, to the extent applicable, standards that concern pipeline systems, or pipelines, generally. Proposed standards that concern only pipe, such as §§ 195.583 and 195.585, do not apply to breakout tanks because these standards do not affect parts of pipelines other than pipe.

Section 195.553 Qualification of Supervisors

The new personnel qualification standards in subpart G of part 195 (64 FR 46866; Aug. 27, 1999) apply to individuals who perform covered tasks on pipelines, including regulated corrosion control activities. However, supervision of covered tasks is not, itself, a covered task. So supervision of corrosion control activities does not come under Subpart G.

We know that prevention of corrosion-caused accidents does not depend solely on how well personnel perform covered tasks on pipelines. Prevention also depends on the correctness of critical decisions that flow from those tasks. Indeed, many Part 195 corrosion control standards require operators not only to perform tasks on pipelines, but to decide if corrective action is needed as a result of the tasks. For example, under § 195.416(d), operators must periodically inspect bare pipe and then determine if cathodic protection is needed.

Individuals assigned to perform covered corrosion control tasks on pipelines, such as collecting pipe-to-soil data, may be qualified under subpart G without knowing what corrective action, if any, should be taken as a result of the tasks. Generally these critical corrosion control decisions are made by supervisory personnel who are in charge of carrying out the corrosion control procedures under § 195.402(c). It is reasonable, we think, that individuals who direct others to carry out corrosion control procedures should have sufficient knowledge of the procedures so they understand what they are directing.

At present, § 195.403(c) regulates the qualifications of individuals assigned to supervise the performance of corrosion control procedures. This rule requires each operator to ''require and verify that its supervisors maintain a thorough knowledge of that portion of the procedures established under § 195.402 for which they are responsible to insure compliance.'' However, § 195.403(c) has been changed. On October 28, 2002, this rule will apply only to supervisors of emergency response procedures (64 FR 46866). Consequently, we are proposing, under § 195.553, to preserve the substance of § 195.403(c) as it now applies to supervisors of corrosion control procedures.

Section 195.555 External Corrosion Control; Applicability

Proposed § 195.555 designates the pipelines covered by proposed §§ 195.557, 195.559, and 195.561. As stated below, these three proposed standards are identical to the present corrosion control standards in §§ 195.238, 195.242, and 195.244 governing coating, cathodic protection, and test leads. Like the standards they would replace, the proposed standards would apply only to pipelines constructed, relocated, replaced, or otherwise changed after §§ 195.238, 195.242, and 195.244 went into effect and to certain converted pipelines (see § 195.5(b)). The effective dates of §§ 195.238, 195.242, and 195.244 are given in § 195.401(c) and vary by pipeline. Proposed § 195.555 cross-references §§ 195.401(c) and 195.5(b).

One other existing corrosion control standard, § 195.236, applies to the same pipelines as §§ 195.238, 195.242, and 195.244. But this standard, which requires protection against external corrosion, is written in terms that may be too general. We think the standard adds nothing substantive to the more specific requirements for external corrosion protection in §§ 195.238 and 195.242. So we are proposing to drop § 195.236 and not include it in proposed subpart H.

[5] ''Breakout tank'' is defined in § 195.2 as ''a tank used to (a) relieve surges in a hazardous liquid pipeline system or (b) receive and store hazardous liquids transported by a pipeline for reinjection and continued transportation by pipeline.''

Section 195.557 External Corrosion Control; Protective Coating

Proposed § 195.557 is identical to § 195.238, which prescribes standards for external coating on certain buried or submerged pipeline components.

Section 195.559 External Corrosion Control; Cathodic Protection System

Proposed § 195.559 is identical to § 195.242, which requires certain buried or submerged facilities to be cathodically protected.

Section 195.561 External Corrosion Control; Test Leads

Proposed § 195.561 is substantially the same as § 195.244, which prescribes standards for the installation of test leads to measure cathodic protection on certain onshore pipelines. However, we are also proposing that at the connection to the pipeline, each bared test lead wire and bared metallic area must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire. This provision is now in effect for gas pipelines under § 192.471(c).

Section 195.563 External Corrosion Control; Additional Cathodic Protection Requirements

Proposed § 195.563 is comparable to § 195.414(a), which requires all effectively coated pipelines to be cathodically protected, except for piping in breakout tank areas and pump stations. To avoid any duplication of proposed § 195.559, proposed § 195.563 would apply only to pipelines that are not protected under proposed § 195.559. Also, we omitted the compliance dates in § 195.414(a) from proposed § 195.563 because the dates have passed.

Section 195.565 External Corrosion Control; Examination of Buried Pipeline When Exposed

Proposed § 195.565 is comparable to existing § 195.416(e), which requires operators to investigate the extent of active corrosion found on exposed pipelines. We recently revised a parallel standard, § 192.459, to clarify the means and bounds of corrosion investigations on exposed gas pipelines (64 FR 56978; Oct. 22, 1999). In view of this rule change, we used § 192.459 as a model for proposed § 195.565 to provide the same clarity for similar investigations required on hazardous liquid and carbon dioxide pipelines. We believe this proposal and the associated recordkeeping under proposed § 195.587 are consistent with SIRRC's suggested changes to § 192.459 quoted above in the discussion of NAPSR's § 192.459 recommendation. Under proposed § 195.565, operators may use indirect methods, including electrical surveys or smart pigs, besides excavation and observation to look for corrosion in the vicinity of an exposed portion of pipeline.

During the course of looking for corrosion on an exposed pipeline, operators observe the condition of protective coating on the pipeline. Proposed § 195.565 would codify this inherent step by requiring operators to first see if the coating is deteriorated before they examine the exposed pipeline for corrosion. Operators' records of inspections preserve information about examinations of exposed pipe for future use, such as assessing the condition of the pipeline for purposes of corrosion control. We think the combination of proposed § 195.565 and records of examinations of exposed pipe would provide an adequate response to NTSB recommendation P–98–35 that part 195 require operators to determine the condition of external coating on exposed pipelines. Proposed § 195.587 (see below) would require operators to keep records of examinations of exposed pipe for as long as the pipe remains in service rather than 2 years as now required by § 195.404(c)(3).

Section 195.567 External Corrosion Control; Cathodic Protection Criteria

NTSB has recommended that Part 195 include performance measures for the adequacy of cathodic protection (recommendation P–98–36). We support NTSB's recommendation. Consequently, we are proposing, in § 195.567, that cathodic protection comply with the criteria and other considerations in section 6 of NACE Standard RP0169–96.

In developing this proposal, we considered that in our experience operators universally apply either NACE criteria or criteria in appendix D of part 192 to determine the adequacy of cathodic protection on pipelines that come under part 195. Similarly, the comments we received on performance measures for cathodic protection were divided between the NACE criteria and the appendix D criteria. And in its April 1995 report of a review of the part 195 standards, NAPSR supported either set of criteria.

While NACE and Appendix D criteria overlap in many respects, two Appendix D criteria (300 mV shift and E-log-I) are not among the NACE criteria. We believe they were omitted because they are outmoded and lack technical validation; and the comments did not dissuade us of this concern. Given our uncertainty about appendix D, we felt compelled to limit our proposal to section 6 of NACE Standard RP0169–96.

Still it is important to recognize that under proposed § 195.567 operators would not have to use only criteria included in section 6 of NACE Standard RP0169–96. Paragraph 6.2.1 of NACE Standard RP0169–96 permits operators to use any criteria that achieves corrosion control comparable to that attained with criteria included in section 6. In addition, paragraph 6.2.1 permits operators to continue to use on existing pipelines criteria that have been successfully applied to those pipelines. Thus proposed § 195.567 would not deny operators the opportunity to use appendix D criteria that are not included in section 6 of NACE Standard RP0169–96 as long as the operators can meet the tests of comparability or successful application stated in paragraph 6.2.1 for the use of alternative criteria. Although section 6 of NACE Standard RP0169–96 does not provide measures of comparability or successful application, to comply with paragraph 6.2.1, we believe there would have to be an absence of corrosion leaks on the pipeline between cathodic protection inspections. And, if the integrity of the pipeline has been checked between cathodic protection inspections by an internal inspection device, pressure testing, or direct examination, there would have to be no signs of metal loss due to corrosion.

On the issue of correct application of the negative (cathodic) 0.85 volt criterion, we find no difference between the NACE and appendix D criteria. Both require that voltage drops other than those across the structure-to-electrolyte boundary must be ''considered'' for valid interpretation of measurements taken for the negative (cathodic) 0.85 volt criterion. NACE explains that consideration means the application of sound engineering practice in determining the significance of voltage drops by methods such as measuring or calculating the voltage drop, reviewing the historical performance of the cathodic protection system, evaluating the physical and electrical characteristics of the pipe and its environment, and determining whether or not there is physical evidence of corrosion.

Section 195.569 External Corrosion Control; Monitoring

Proposed § 195.569(a) is substantially the same as § 195.416(a), which requires annual tests of the adequacy of cathodic protection. The only difference is that proposed § 195.569(a) references proposed § 195.567 as the measure of adequacy. Proposed § 195.569(b) is identical to § 195.416(c), which requires bimonthly inspections of cathodic protection rectifiers. Although proposed § 195.569(d) has no parallel in part 195, it is comparable to § 192.465(c), which requires periodic inspections of items critical to cathodic protection. We think such inspections are common practice on pipelines subject to part 195. Proposed § 195.569(e) is identical to § 195.416(j), which requires inspections of systems used to protect the bottoms of aboveground breakout tanks.

Proposed § 195.569(c) is comparable to existing § 195.416(d), which requires electrical inspection of unprotected ''bare pipe'' [6] at least every 5 years to determine if protection is needed. However, like § 192.465(e), proposed § 195.569(c) would clarify that the purpose of the inspections is to detect ''active corrosion'' and would allow operators to use alternative means of determining active corrosion where an electrical survey is impractical. The term ''active corrosion'' would be defined essentially as it is in § 192.457(c), but with the additional consideration of risk to the environment. Moreover, as SIRRC recommended for gas pipelines under § 192.465(e) (see above), the alternative means of determining active corrosion would have to include an analysis and review of the pipeline's condition, based on leak repair history, exposed pipe inspection records, and the pipeline environment. In accordance with SIRRC's recommendation, we also included definitions of ''electrical survey'' and ''pipeline environment'' in proposed § 195.569(c).

Another difference between proposed §§ 195.569(c) and 195.416(d) is that, like § 192.465(e), proposed § 195.569(c) would require inspections of all unprotected pipelines, not just unprotected bare pipe. The impact of this change would be on unprotected buried piping in breakout tank areas and pump stations. At present, part 195 does not have a periodic inspection requirement for corrosion on unprotected piping in breakout tank areas and pump stations. [7] Only minor costs should result from this change in coverage, for we believe that periodic inspection of unprotected piping in breakout tank areas and pump stations is a common industry practice. The requirements for initial electrical inspection of bare pipelines (§ 195.414 (b)) and of piping in breakout tank areas and pump stations (§ 195.414(c)) have not been included in proposed Subpart H because the periods allowed for compliance have expired.

We have not proposed to increase the minimum frequency of inspections from every 5 years to every 3 years, which is the minimum frequency required by § 192.465(e) for inspecting unprotected gas pipelines. Our safety data do not show that increasing the minimum frequency to every 3 years would be likely to result in fewer reported corrosion-caused accidents on hazardous liquid or carbon dioxide pipelines. Moreover, the ASME B31.4 Code, a set of voluntary safety standards widely followed by operators of pipelines subject to part 195, specifies a minimum frequency of every 5 years for inspecting unprotected pipelines. While NACE Standard RP0169–96 requires periodic inspections to determine the need to protect unprotected pipelines, it does not prescribe the frequency of those inspections.

We also considered the need to propose a standard comparable to § 192.465(d), which requires gas pipeline operators to take ''prompt'' remedial action to correct any deficiencies detected by monitoring external corrosion control. But we decided such a proposal is unnecessary because § 195.401(b) requires operators to correct within a reasonable time any condition that could adversely affect safe operation, and if an immediate hazard exists, to cease operating the affected facility until the condition is corrected. Also, § 195.401(b) regulates the timing of corrective responses to any unsafe corrosion control deficiency, not just deficiencies in external corrosion control.

Section 195.571 External Corrosion Control: Electrical Isolation

Proposed § 195.571 is comparable to § 192.467, which requires electrical isolation on gas pipelines to provide for adequate cathodic protection and safeguards for insulating devices. Such isolation is also a common practice on pipelines subject to part 195. However, we are not proposing to include the requirements of § 192.467(c) concerning isolation of pipelines from metallic casings. We agree with GPTC and commenters who believe the safety need to clear shorted casings is not apparent. Therefore, we have not included in proposed Subpart H SIRRC's recommended measures to remedy shorted casings.

Section 195.573 External Corrosion Control: Test Stations

Proposed § 195.573 is identical to § 195.416(b), which requires maintenance of test leads to provide for monitoring the adequacy of cathodic protection.

Section 195.575 External Corrosion Control: Interference Currents

Proposed § 195.575 is comparable to § 192.473, which requires operators to minimize the detrimental effects of interference currents on gas pipelines and adjacent structures. Although at present there are no standards in part 195 concerning interference problems, we believe that most operators already have a testing program to minimize interference problems. Proposed § 195.575 has minor editorial differences from the wording of § 192.473.

Section 195.577 Internal Corrosion Control

Proposed § 195.577 is comparable to § 195.418, which requires protective measures to mitigate the effects of internal corrosion. However, proposed § 195.577(d) differs somewhat from § 195.418(d), which requires operators to investigate the extent of general corrosion found inside pipe that is removed from a pipeline. Proposed § 195.577(d) would clarify the required investigation by adopting wording similar to that of proposed § 195.565, which concerns the extent of external corrosion on exposed pipe. Also, under proposed § 195.577(d), an investigation would be required if the removed pipe is corroded to the extent that it must be remedied under proposed § 195.583, rather than if the pipe is generally corroded such that the wall thickness is less than that required by the pipe's specification tolerances, as § 195.418(d) now requires. This change would allow operators to take full advantage of criteria for determining the strength of corroded pipe (see proposed § 195.585). The change would also require consideration of the effect of corrosion pitting as well as general corrosion, consistent with the parallel requirement for gas pipelines in § 192.475(b).

Another difference between the proposed and existing standards is that proposed § 195.577(d) drops the remedial measures § 195.418(d) prescribes for corroded pipe. Remedial measures for corroded pipe would be governed by proposed § 195.583. This change would improve the present rule by basing the need for remediation on the strength of corroded pipe and by allowing the use of qualified repair

[6] The term ''bare pipe'' refers to pipe that is bare and to pipe that is ineffectively coated (see § 195.414(a)).

[7] Bare pipe and piping in breakout tank areas and pump stations are treated separately under § 194.414. So we do not consider unprotected piping in breakout tank areas and pump stations to come under the requirements of § § 194.416(d) concerning the periodic inspection of bare pipe.

methods that are not allowed under § 195.418(d).

Section 195.579 Atmospheric Corrosion Control; General

Proposed § 195.579 is comparable to § 195.416(i), which requires that all pipelines exposed to the atmosphere must be protected against atmospheric corrosion by a suitable coating. The comments indicate § 195.416(i) may be overly burdensome, because it does not give operators leeway to avoid coating pipelines that have only a harmless light surface oxide or other mild form of corrosion that is unlikely to harm the pipeline before the next scheduled inspection. So proposed § 195.579 includes an exception for these circumstances. The test, investigation, or experience used to justify an exception must be appropriate to the environment of the particular pipeline facility. In addition, this exception would not apply to splash zones of offshore pipelines or to soil-to-air interfaces of onshore pipelines.

We did not adopt SIRRC's recommendation regarding comparable § 192.479 (see above) to except all but ''active corrosion'' from the atmospheric corrosion protection requirement. The intent of the recommendation is to distinguish harmless rust from serious metal loss, but we believe this objective is better accomplished by more descriptive wording.

Section 195.581 Atmospheric Corrosion Control; Monitoring

Proposed § 195.581 is comparable to § 192.481, which requires operators of gas pipelines to reevaluate the adequacy of atmospheric corrosion protection at least every 3 years on onshore pipelines and at least every year on offshore pipelines. Although § 195.416(i) requires maintenance of protection on hazardous liquid and carbon dioxide pipelines, this standard may be too general because it lacks minimum inspection frequencies.

In deciding what inspection frequency is most appropriate for onshore pipelines, we considered the majority of comments on § 192.481 that favored lengthening the minimum inspection frequency from every 3 years to every 5 years. But we gave section 463.3 of the ASME B31.4 Code greater weight. This voluntary code, which is widely followed by operators of pipelines subject to Part 195, specifies a minimum 3-year inspection frequency for atmospheric corrosion protection onshore. We also considered that GPTC, in its recommendation regarding § 192.481, did not suggest extending the minimum 3-year frequency more than a marginal amount to provide flexibility. Also, two commenters said the present 3-year frequency is not too burdensome. There were no comments on the frequency of inspection offshore, and the ASME B31.4 Code does not specify a minimum frequency.

Proposed § 195.581 would require periodic ''inspection'' rather than ''reevaluation'' to avoid the possibility that decisions about the adequacy of protection might not be based on current observations. The proposed rule also recognizes the importance of paying special attention during inspections to particular pipeline areas that have historically been sources of corrosion problems, such as splash zones and pipe surfaces underneath thermal insulation. We feel that most operators already inspect aboveground pipelines for corrosion at the proposed frequencies and give careful attention to potential problem areas.

Section 195.583 Remedial Measures; General

Proposed § 195.583(a) is comparable to § 195.416 (f), which regulates the repair of pipe that has general corrosion.[8] But proposed § 195.583(a) reflects the wording of § 192.485(a), a repair rule similar to § 195.416(f) that bases the need for corrective action on whether the remaining wall thickness supports the maximum allowable operating pressure. At present, § 195.416 (f) bases the need for corrective action on whether the remaining wall thickness is within the pipe specification tolerances. The revised wording would allow operators to take full advantage of criteria for determining the strength of corroded pipe (see proposed § 195.585). Proposed § 195.583(b) is identical to § 195.416(g), which regulates remedial measures for localized corrosion pitting.

Section 195.585 Remedial Measures; Remaining Strength

Proposed § 195.585 is substantially the same as § 195.416(h), which authorizes the use of widely accepted criteria for determining the remaining strength of corroded pipe.

Section 195.587 Records

For hazardous liquid and carbon dioxide pipelines, requirements to keep records related to corrosion control are in § 195.404. Under § 195.404(a), operators must maintain current maps and records that identify and show the location of facilities that are cathodically protected. In addition, § 195.404(c)(3) requires operators to keep records of required inspections and tests for at least 2 years or until the next inspection or test, whichever is longer.

We are proposing to adopt new recordkeeping requirements for hazardous liquid and carbon dioxide pipelines comparable to those for gas pipelines in § 192.491. Under proposed § 195.587(a), operators would have to keep current records or maps of the location of cathodically protected piping (as they must now under § 195.404(a)), of cathodic protection facilities, and of bonded structures. Also, under proposed § 195.587(b), operators would have to keep a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by proposed Subpart H in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. Records required by § 195.587(b) would have to be retained for at least 5 years, except that records related to determining the adequacy of, or need for, external or internal corrosion control (records related to proposed §§ 195.565, 195.569(a) and (c), and 195.577(c) and (d)) would have to be kept as long as the pipeline is in service.

The majority of comments on the appropriate period to keep records related to determining if external or internal corrosion control is adequate or needed did not support keeping these records for as long as the pipeline remains in service. Instead they mostly suggested a retention period of 5 years or the next one or two monitoring cycles, whichever is longer. But we agree with the single commenter who said keeping such records for the service life of the pipeline provides a very helpful general history. In our experience, a history of corrosion control monitoring is very useful in assessing the condition of a pipeline. If corrosion problems emerge on a pipeline, its monitoring history is considered in deciding the extent and kind of remedial action needed.

As for other records under proposed § 195.587(b) (*e.g.*, records of rectifier inspections under proposed § 195.569(b)), we believe the retention period must be compatible with the normal cycle of routine compliance investigations by government inspection personnel and long enough to provide meaningful history for investigation of an accident or safety problem. A minimum 5-year retention requirement would assure that the records are available during routine inspection

[8] Section 195.416(f) was revised by Amendment 195–68 (64 FR 69660; Decemeber 14, 1999).

visits, and provide a more complete history for analyzing problems.

Proposed § 195.587(a)(2), which is based on § 192.491(a), would require operators to have current records or maps identifying the location of cathodic protection facilities, galvanic anodes, and structures bonded to cathodic protection systems. Such records are not now required by Part 195, and although operators may have them, to minimize the recordkeeping burden, the records would only be required for installations made after the final rule goes into effect.

The record retention times proposed by § 195.587(b) would only apply to records of actions that occur after Subpart H takes effect. The retention times now required by § 195.404(c)(3) would continue to apply to records of corrosion tests and inspections done before Subpart H takes effect.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Policies and Procedures

RSPA does not consider this proposed rulemaking to be a significant regulatory action under Section 3(f) of Executive Order 12866 (58 FR 51735; Oct. 4, 1993). Therefore, the Office of Management and Budget (OMB) has not received a copy of this rulemaking to review. RSPA also does not consider this proposed rulemaking to be significant under DOT regulatory policies and procedures (44 FR 11034: February 26, 1979).

We prepared a Draft Regulatory Evaluation of the proposed rules and a copy is in the docket. The evaluation states that the proposed rules are, on the whole, comparable either to existing safety standards currently in part 195 for hazardous liquid pipelines or to existing safety standards in part 192 for gas pipelines. The evaluation also states that the information presented at public meetings and meetings with industry and state representatives strongly suggests that imposing gas pipeline safety standards for corrosion control on hazardous liquid pipelines would not require a significant departure from customary safety practices on liquid pipelines.

An important feature of the proposed rules not found in part 192 or part 195 is the reference to cathodic protection criteria in NACE Standard RP0169–96. The evaluation states that these criteria are well known and widely followed throughout the industry, as indicated by meetings with industry representatives and by the voluntary standards in the ASME B31.4 Code. The evaluation further states that operators who do not now apply the NACE criteria are likely to apply the criteria in appendix D of part 192. The proposed rules would allow use of appendix D criteria under conditions stated in the NACE standard.

The evaluation concludes there should be only minimal additional cost, if any, for operators to comply with the proposed rules. If you disagree with this conclusion, please provide information to the public docket described above.

Regulatory Flexibility Act

The proposed rules are consistent with customary practices for corrosion control in the hazardous liquid and carbon dioxide pipeline industry. Therefore, based on the facts available about the anticipated impacts of this proposed rulemaking, I certify, pursuant to section 605 of the Regulatory Flexibility Act (5 U.S.C. 605), that this proposed rulemaking would not have a significant impact on a substantial number of small entities. If you have any information that this conclusion about the impact on small entities is not correct, please provide that information to the public docket described above.

Executive Order 13084

The proposed rules have been analyzed in accordance with the principles and criteria contained in Executive Order 13084, ‘‘Consultation and Coordination with Indian Tribal Governments.’’ Because the proposed rules would not significantly or uniquely affect the communities of the Indian tribal governments and would not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Paperwork Reduction Act

Section 195.587 proposes minor additional information collection requirements. Operators would be required to record the location of certain newly installed protection facilities, and keep the records for as long as the pipeline concerned is in service. In addition, records of inspections, tests, and surveys would have to be kept for as long as the pipeline is in service or for 5 years, depending on the nature of the information recorded. The present minimum retention period for these records is 2 years or the prescribed interval of test or inspection, whichever is longer (up to 5 years in some cases).

However, we believe operators already maintain records of the location of their protection facilities for as long as the pipeline is in service to be able to find the facilities for their own purposes and to carry out existing monitoring requirements in part 195. Also, we believe the burden of retaining inspection, test, and survey records for the longer period proposed would be minimal. These records are largely computerized. Maintaining these records on a floppy disk or computer file represents very minimal costs. So, because the additional paperwork burdens of this proposed rule are likely to be minimal, we believe that submitting an analysis of the burdens to OMB under the Paperwork Reduction Act is unnecessary. If you disagree with this conclusion, please submit your comments to the public docket.

Unfunded Mandates Reform Act of 1995

This proposed rulemaking would not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It would not result in costs of $100 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector, and would be the least burdensome alternative that achieves the objective of the rule.

National Environmental Policy Act

We have analyzed the proposed rules for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*). Because the proposed rules parallel present requirements or practices, we have preliminarily determined that the proposed rules would not significantly affect the quality of the human environment. An environmental assessment document is available for review in the docket. A final determination on environmental impact will be made after the end of the comment period. If you disagree with our preliminary conclusion, please submit your comments to the docket as described above.

Impact on Business Processes and Computer Systems

We do not want to impose new requirements that would mandate business process changes when the resources necessary to implement those requirements would otherwise be applied to ‘‘Y2K’’ or related computer problems. The proposed rules would not mandate business process changes or require modifications to computer systems. Because the proposed rules would not affect the ability of organizations to respond to those problems, we are not proposing to delay the effectiveness of the requirements.

Executive Order 13132

The proposed rules have been analyzed in accordance with the principles and criteria contained in Executive Order 13132 (‘‘Federalism’’).

The proposed rules do not propose any regulation that (1) has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government; (2) imposes substantial direct compliance costs on State and local governments; or (3) preempts state law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply. Nevertheless, during our review of the existing corrosion control standards, representatives of state pipeline safety agencies gave us advice both in private sessions and in the two public meetings we held. In addition, our pipeline safety advisory committees, which include representatives of state governments, were, on two occasions in 1999, briefed on the corrosion control review project.

List of Subjects in 49 CFR Part 195

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

In consideration of the foregoing, we propose to amend 49 CFR part 195 as follows:

PART 195—[AMENDED]

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

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118; and 49 CFR 1.53.

2. Section 195.3 would be amended by adding paragraphs (b)(8) and (c)(7) to read as follows:

§ 195.3 Matter incorporated by reference.

* * * * *

(b) * * *

(8) NACE International, 1440 South Creek Drive, Houston, TX 77084.

(c) * * *

(7) NACE International (NACE):

(i) NACE Standard RP0169–96, ''Control of External Corrosion on Underground or Submerged Metallic Pipeline Systems'' (1996).

(ii) [Reserved]

3. Section 195.5(b) would be revised to read as follows:

§ 195.5 Conversion to service subject to this part.

* * * * *

(b) A pipeline which qualifies for use under this section need not comply with the corrosion control requirements of subpart H of this part until 12 months after it is placed in service, notwithstanding any earlier deadlines for compliance. The requirements of §§ 195.557, 195.559, and 195.561 apply to each pipeline which substantially meets those requirements before it is placed in service or which is a segment that is replaced, relocated, or substantially altered.

* * * * *

4. Section 195.402(c)(3) would be revised to read as follows:

§ 195.402 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(c) * * *

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

* * * * *

§ 195.404 [Amended]

5. In § 195.404, paragraph (a)(1)(v) would be removed, and paragraphs (a)(1)(vi) through (a)(1)(viii) would be redesignated as paragraphs (a)(1)(v) through (a)(1)(vii).

§§ 195.236, 195.238, 195.242, 195.244, 195.414, 195.416, 195.418 [Removed]

6. The following sections would be removed and reserved: §§ 195.236, 195.238, 195.242, 195.244, 195.414, 195.416, and 195.418.

7. Subpart H would be added to read as follows:

Subpart H—Corrosion Control

Subpart H—Corrosion Control

§ 195.551 Scope.

This subpart prescribes minimum requirements for protecting steel pipelines against corrosion.

§ 195.553 Qualification of supervisors.

Each operator must require and verify that its supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under § 195.402 for which they are responsible for insuring compliance.

§ 195.555 External corrosion control; Applicability.

The requirements of §§ 195.557, 195.559, and 195.561 apply only to—

(a) Pipelines constructed, relocated, replaced, or otherwise changed after the applicable date in § 195.401(c); and

(b) Converted pipelines, if required by § 195.5(b).

§ 195.557 External corrosion control; Protective coating.

(a)(1) No component of a pipeline may be buried or submerged unless that component has an external protective coating that—

(i) Is designed to mitigate corrosion of the buried or submerged component;

(ii) Has sufficient adhesion to the metal surface to prevent under film migration of moisture;

(iii) Is sufficiently ductile to resist cracking;

(iv) Has enough strength to resist damage due to handling and soil stress; and

(v) Supports any supplemental cathodic protection.

(2) In addition, if any insulating-type coating is used, it must have low moisture absorption and provide high electrical resistance.

(b) All pipe coating must be inspected just prior to lowering the pipe into the ditch or submerging the pipe, and any damage discovered must be repaired.

§ 195.559 External corrosion control; Cathodic protection system.

(a) A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A test procedure must be developed to determine whether adequate cathodic protection has been achieved.

(b) A cathodic protection system must be installed not later than 1 year after completing the construction.

(c) For the bottoms of aboveground breakout tanks with greater than 500 barrels (79.5 m^3) capacity built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor

Standard 12C), the installation of a cathodic protection system under paragraph (a) of this section after October 2, 2000, must be in accordance with API Recommended Practice 651, unless the operator notes in the procedural manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of a particular breakout tank.

(d) For the internal bottom of aboveground breakout tanks built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), the installation of a tank bottom lining after October 2, 2000, must be in accordance with API Recommended Practice 652, unless the operator notes in the procedural manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 652 is not necessary for the safety of a particular breakout tank.

§ 195.561 External corrosion control; Test leads.

(a) Except for offshore pipelines, electrical test leads used for corrosion control or electrolysis testing must be installed at intervals frequent enough to obtain electrical measurements indicating the adequacy of the cathodic protection.

(b) Test leads must be installed as follows:

(1) Enough looping or slack must be provided to prevent test leads from being unduly stressed or broken during backfilling.

(2) Each lead must be attached to the pipe so as to prevent stress concentration on the pipe.

(3) Each lead installed in a conduit must be suitably insulated from the conduit.

(4) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§ 195.563 External corrosion control; Additional cathodic protection requirements.

(a) Each pipeline not subject to § 195.559 that has an effective external surface coating material must be cathodically protected. This requirement does not apply to breakout tank areas and buried pumping station piping.

(b) For the purposes of this subpart, a pipeline does not have an effective external coating and shall be considered bare if the current required to cathodically protect it is substantially the same as if it were bare.

§ 195.565 External corrosion control; Examination of a buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion, if the pipe is bare or if the coating is deteriorated. If external corrosion requiring remedial action under § 195.583 is found, the operator must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

§ 195.567 External corrosion control; Cathodic protection criteria.

Cathodic protection required by this subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in section 6 of NACE Standard RP0169–96.

§ 195.569 External corrosion control; Monitoring.

(a) Each operator must, 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 under § 195.567.

(b) Each operator must, at intervals not exceeding 2½ months, but at least six times each calendar year, inspect each of its cathodic protection rectifiers.

(c) Each operator must, at intervals not exceeding 5 years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey, or where an electrical survey is impractical, by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. In this section:

(1) *Active corrosion* means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety or the environment.

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

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

(d) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structural protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(e) For aboveground breakout tanks where corrosion of the tank bottom is controlled by a cathodic protection system, the cathodic protection system must be inspected to ensure it is operated and maintained in accordance with API Recommended Practice 651, unless the operator notes in the procedure manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of a particular breakout tank.

§ 195.571 External corrosion control; Electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(d) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(e) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

§ 195.573 External corrosion control; Test stations.

Each operator must maintain the test leads required for cathodic protection in such a condition that electrical measurements can be obtained to ensure adequate protection.

§ 195.575 External corrosion control; Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents must have a program to identify, test for, and minimize the detrimental effects of such currents.

(b) Each impressed current or galvanic anode system must be designed and installed to minimize any adverse effects on existing adjacent metallic structures.

§ 195.577 Internal corrosion control.

(a) No operator may transport any hazardous liquid or carbon dioxide that would corrode the pipe or other components of its pipeline system, unless it has investigated the corrosive effect of the hazardous liquid or carbon dioxide on the system and has taken adequate steps to mitigate corrosion.

(b) If corrosion inhibitors are used to mitigate internal corrosion the operator must use inhibitors in sufficient quantity to protect the entire part of the system that the inhibitors are designed to protect and shall also use coupons or other monitoring equipment to determine their effectiveness.

(c) The operator must, at intervals not exceeding 7½ months, but at least twice each calendar year, examine coupons or other types of monitoring equipment to determine the effectiveness of the inhibitors or the extent of any corrosion.

(d) Whenever pipe is removed from a pipeline, the operator must inspect the internal surface of the pipe for evidence of corrosion. If internal corrosion requiring remedial action under § 195.583 is found, the operator shall investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

§ 195.579 Atmospheric corrosion control; General.

Each pipeline or portion of pipeline that is exposed to the atmosphere must be cleaned and coated with a material suitable for the prevention of atmospheric corrosion. However, except for portions of pipelines in offshore splash zones and soil-to-air interfaces, protection against atmospheric corrosion is not required if the operator demonstrates by test, investigation, or experience that corrosion will be limited to a light surface oxide or else will not affect the safe operation of the pipeline before the next scheduled inspection.

§ 195.581 Atmospheric corrosion control; Monitoring.

(a) Each operator must, at intervals not exceeding 3 years for onshore pipelines or 15 months, but at least once each calendar year, for offshore pipelines, inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion. Particular attention must be given to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(b) If atmospheric corrosion is found, the operator must provide protection against atmospheric corrosion as required by § 195.579.

§ 195.583 Remedial measures; General.

(a) Any pipe that is found to be generally corroded so that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline must be replaced. However, generally corroded pipe need not be replaced if—

(1) The operating pressure is reduced to be commensurate with the strength of the pipe, based on the actual remaining wall thickness; or

(2) The pipe is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) 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.

§ 195.585 Remedial Measures; Remaining strength.

Under § 195.583, 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 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.

§ 195.587 Records.

(a) Each operator must maintain current records or maps to show the location of—

(1) Cathodically protected pipelines;

(2) Cathodic protection facilities and galvanic anodes installed after [effective date of final rule]; and

(3) Neighboring structures bonded to cathodic protection systems. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each operator must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. These records must be retained for at least 5 years, except that records related to §§ 195.565, 195.569(a) and (c), and 195.577(c) and (d) must be retained for as long as the pipeline remains in service.

Issued in Washington, DC on December 1, 2000.

Stacey L. Gerard,

Associate Administrator for Pipeline Safety.

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