CHANGES BY SPECIFIC CITATION RECENT FINAL RULEMAKING

Effective Date:
03/24/2017

PHMSA is amending 49 CFR parts 190, 191, 192, 195, and 199 as follows:

PART 190—PIPELINE SAFETY ENFORCEMENT AND REGULATORY PROCEDURES

1. The authority citation for part 190 continues to read as follows:


2. In §190.3, add the definition “New and novel technologies” in alphabetical order to read as follows:

   §190.3 Definitions.

   New and novel technologies means any products, designs, materials, testing, construction, inspection, or operational procedures that are not addressed in 49 CFR parts 192, 193, or 195, due to technology or design advances and innovation for new construction. Technologies that are addressed in consensus standards that are incorporated by reference into parts 192, 193, and 195 are not “new or novel technologies.”

3. Amend §190.341 by:

   a. Revising paragraph (c)(8) and removing paragraph (c)(9) and revising paragraph (d);

   b. Re-designating paragraphs (e) through (j) as paragraphs (g) through (l) and adding new paragraphs (e) and (f).

   The additions and revisions read as follows:

   §190.341 Special permits.

   (c) * * *

   (8) Any other information PHMSA may need to process the application including environmental analysis where necessary.

   (d) How does PHMSA handle special permit applications?—(1) Public notice. Upon receipt of an application or renewal of a special permit, PHMSA will provide notice to the public of its intent to consider the application and invite comment. In addition, PHMSA
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may consult with other Federal agencies before granting or denying an application or renewal on matters that PHMSA believes may have significance for proceedings under their areas of responsibility.

(2) Grants, renewals, and denials. If the Associate Administrator determines that the application complies with the requirements of this section and that the waiver of the relevant regulation or standard is not inconsistent with pipeline safety, the Associate Administrator may grant the application, in whole or in part, for a period of time from the date granted. Conditions may be imposed on the grant if the Associate Administrator concludes they are necessary to assure safety, environmental protection, or are otherwise in the public interest. If the Associate Administrator determines that the application does not comply with the requirements of this section or that a waiver is not justified, the application will be denied. Whenever the Associate Administrator grants or denies an application, notice of the decision will be provided to the applicant. PHMSA will post all special permits on its Web site at http://www.phmsa.dot.gov.

(e) How does PHMSA handle special permit renewals? (1) The grantee of the special permit must apply for a renewal of the permit 180 days prior to the permit expiration. (2) If, at least 180 days before an existing special permit expires the holder files an application for renewal that is complete and conforms to the requirements of this section, the special permit will not expire until final administrative action on the application for renewal has been taken:

(i) Direct fax to PHMSA at: 202-366-4566; or

(ii) Express mail, or overnight courier to the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590.

(f) What information must be included in the renewal application? (1) The renewal application must include a copy of the original special permit, the docket number on the special permit, and the following information as applicable:
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(i) A summary report in accordance with the requirements of the original special permit including verification that the grantee's operations and maintenance plan (O&M Plan) is consistent with the conditions of the special permit;

(ii) Name, mailing address and telephone number of the special permit grantee;

(iii) Location of special permit—areas on the pipeline where the special permit is applicable including: Diameter, mile posts, county, and state;

(iv) Applicable usage of the special permit—original and future; and

(v) Data for the special permit segment and area identified in the special permit as needing additional inspections to include, as applicable:

(A) Pipe attributes: Pipe diameter, wall thickness, grade, seam type; and pipe coating including girth weld coating;

(B) Operating Pressure: Maximum allowable operating pressure (MAOP); class location (including boundaries on aerial photography);

(C) High Consequence Areas (HCAs): HCA boundaries on aerial photography;

(D) Material Properties: Pipeline material documentation for all pipe, fittings, flanges, and any other facilities included in the special permit. Material documentation must include: Yield strength, tensile strength, chemical composition, wall thickness, and seam type;

(E) Test Pressure: Hydrostatic test pressure and date including pressure and temperature charts and logs and any known test failures or leaks;

(F) In-line inspection (ILI): Summary of ILI survey results from all ILI tools used on the special permit segments during the previous five years or latest ILI survey result;
(G) Integrity Data and Integration: The following information, as applicable, for the past five (5) years: Hydrostatic test pressure including any known test failures or leaks; casings (any shorts); any in-service ruptures or leaks; close interval survey (CIS) surveys; depth of cover surveys; rectifier readings; test point survey readings; alternating current/direct current (AC/DC) interference surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; stress corrosion cracking (SCC), selective seam weld corrosion (SSWC) and hard spot excavations and findings; and pipe exposures from encroachments;

(H) In-service: Any in-service ruptures or leaks including repair type and failure investigation findings; and

(I) Aerial Photography: Special permit segment and special permit inspection area, if applicable.

(2) PHMSA may request additional operational, integrity or environmental assessment information prior to granting any request for special permit renewal.

(3) The existing special permit will remain in effect until PHMSA acts on the application for renewal by granting or denying the request.

4. Section 190.343 is added to subpart D read as follows:

§ 190.343
Information made available to the public and request for protection of confidential commercial information.

When you submit information to PHMSA during a rulemaking proceeding, as part of your application for special permit or renewal, or for any other reason, we may make that information publicly available unless you ask that we keep the information confidential. Start Printed Page 7996

(a) Asking for protection of confidential commercial information. You may ask us to give confidential treatment to information you give to the agency by taking the following steps:
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(1) Mark “confidential” on each page of the original document you would like to keep confidential.

(2) Send us, along with the original document, a second copy of the original document with the confidential commercial information deleted.

(3) Explain why the information you are submitting is confidential commercial information.

(b) PHMSA decision. PHMSA will treat as confidential the information that you submitted in accordance with this section, unless we notify you otherwise. If PHMSA decides to disclose the information, PHMSA will review your request to protect confidential commercial information under the criteria set forth in the Freedom of Information Act (FOIA), 5 U.S.C. 552, including following the consultation procedures set out in the Departmental FOIA regulations, 49 CFR 7.29. If PHMSA decides to disclose the information over your objections, we will notify you in writing at least five business days before the intended disclosure date.

5. In part 190, subpart E is added to read as follows:

Subpart E—Cost Recovery for Design Reviews

190.401 Scope.

190.403 Applicability.

190.405 Notification.

190.407 Master Agreement.

190.409 Fee structure.

190.411 Procedures for billing and payment of fee.

§ 190.401 Scope.

If PHMSA conducts a facility design and/or construction safety review or inspection in connection with a proposal to construct, expand, or operate a gas, hazardous liquid or
carbon dioxide pipeline facility, or a liquefied natural gas facility that meets the
applicability requirements in § 190.403, PHMSA may require the applicant proposing the
project to pay the costs incurred by PHMSA relating to such review, including the cost of
design and construction safety reviews or inspections.

§ 190.403
Applicability.

The following paragraph specifies which projects will be subject to the cost recovery
requirements of this section.

(a) This section applies to any project that—

(1) Has design and construction costs totaling at least $2,500,000,000, as periodically
adjusted by PHMSA, to take into account increases in the Consumer Price Index for all
urban consumers published by the Department of Labor, based on—

(i) The cost estimate provided to the Federal Energy Regulatory Commission in an
application for a certificate of public convenience and necessity for a gas pipeline facility
or an application for authorization for a liquefied natural gas pipeline facility; or

(ii) A good faith estimate developed by the applicant proposing a hazardous liquid or
carbon dioxide pipeline facility and submitted to the Associate Administrator. The good
faith estimate for design and construction costs must include all of the applicable cost
items contained in the Federal Energy Regulatory Commission application referenced in
§ 190.403(a)(1)(i) for a gas or LNG facility. In addition, an applicant must take into
account all survey, design, material, permitting, right-of-way acquisition, construction,
testing, commissioning, start-up, construction financing, environmental protection,
inspection, material transportation, sales tax, project contingency, and all other applicable
costs, including all segments, facilities, and multi-year phases of the project;

(2) Uses new or novel technologies or design, as defined in § 190.3.
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(b) The Associate Administrator may not collect design safety review fees under this section and 49 U.S.C. 60301 for the same design safety review.

(c) The Associate Administrator, after receipt of the design specifications, construction plans and procedures, and related materials, determines if cost recovery is necessary. The Associate Administrator's determination is based on the amount of PHMSA resources needed to ensure safety and environmental protection.

§ 190.405
Notification.

For any new pipeline facility construction project in which PHMSA will conduct a design review, the applicant proposing the project must notify PHMSA and provide the design specifications, construction plans and procedures, project schedule and related materials at least 120 days prior to the commencement of any of the following activities: Route surveys for construction, material manufacturing, offsite facility fabrications, construction equipment move-in activities, onsite or offsite fabrications, personnel support facility construction, and any offsite or onsite facility construction. To the maximum extent practicable, but not later than 90 days after receiving such design specifications, construction plans and procedures, and related materials, PHMSA will provide written comments, feedback, and guidance on the project.

§ 190.407
Master Agreement.

PHMSA and the applicant will enter into an agreement within 60 days after PHMSA received notification from the applicant provided in § 190.405, outlining PHMSA’s recovery of the costs associated with the facility design safety review.

(a) A Master Agreement, at a minimum, includes:

(1) Itemized list of direct costs to be recovered by PHMSA;

(2) Scope of work for conducting the facility design safety review and an estimated total cost;
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(3) Description of the method of periodic billing, payment, and auditing of cost recovery fees;

(4) Minimum account balance which the applicant must maintain with PHMSA at all times;

(5) Provisions for reconciling differences between total amount billed and the final cost of the design review, including provisions for returning any excess payments to the applicant at the conclusion of the project;

(6) A principal point of contact for both PHMSA and the applicant; and

(7) Provisions for terminating the agreement.

(8) A project reimbursement cost schedule based upon the project timing and scope.

(b) [Reserved]

§ 190.409
Fee structure.

The fee charged is based on the direct costs that PHMSA incurs in conducting the facility design safety review (including construction review and inspections), and will be based only on costs necessary for conducting the facility design safety review. “Necessary for” means that but for the facility design safety review, the costs would not have been incurred and that the costs cover only those activities and items without which the facility design safety review cannot be completed.

(a) Costs qualifying for cost recovery include, but are not limited to—

(1) Personnel costs based upon total cost to PHMSA;
(2) Travel, lodging and subsistence;

(3) Vehicle mileage;

(4) Other direct services, materials and supplies;

(5) Other direct costs as may be specified in the Master Agreement.

(b) [Reserved]

§ 190.411
Procedures for billing and payment of fee.

All PHMSA cost calculations for billing purposes are determined from the best available PHMSA records.

(a) PHMSA bills an applicant for cost recovery fees as specified in the Master Agreement, but the applicant will not be billed more frequently than quarterly.

(1) PHMSA will itemize cost recovery bills in sufficient detail to allow independent verification of calculations.

(2) [Reserved]

(b) PHMSA will monitor the applicant's account balance. Should the account balance fall below the required minimum balance specified in the Master Agreement, PHMSA may request at any time the applicant submit payment within 30 days to maintain the minimum balance.

(c) PHMSA will provide an updated estimate of costs to the applicant on or near October 1st of each calendar year.
(d) Payment of cost recovery fees is due within 30 days of issuance of a bill for the fees. If payment is not made within 30 days, PHMSA may charge an annual rate of interest (as set by the Department of Treasury's Statutory Debt Collection Authorities) on any outstanding debt, as specified in the Master Agreement.

(e) Payment of the cost recovery fee by the applicant does not obligate or prevent PHMSA from taking any particular action during safety inspections on the project.

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS

6. The authority citation for part 191 is revised to read as follows:

Authority: 49 U.S.C. 5121, 60102, 60103, 60104, 60108, 60117, 60118, 60124, 60132, and 60141; and 49 CFR 1.97.

7. In § 191.3, add the definition “Confirmed Discovery” in alphabetical order to read as follows:

§ 191.3
Definitions.

Confirmed Discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.

8. In § 191.5, paragraph (a) is revised and paragraph (c) is added to read as follows:

§ 191.5
Immediate notice of certain incidents.

(a) At the earliest practicable moment following discovery, but no later than one hour after confirmed discovery, each operator must give notice in accordance with paragraph (b) of this section of each incident as defined in § 191.3.

(c) Within 48 hours after the confirmed discovery of an incident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in paragraph (b) of this section with an estimate of the amount of product released, an estimate of the number
of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.

9. In § 191.22, paragraph (c)(1)(ii) is revised and paragraphs (c)(1)(v) and (c)(1)(vi) are added to read as follows:

§ 191.22
National Registry of Pipeline and LNG operators

(c) ** *

(1) ** *

(ii) Construction of 10 or more miles of a new or replacement pipeline;

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

(vi) A pipeline converted for service under § 192.14 of this chapter, or a change in commodity as reported on the annual report as required by § 191.17.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

10. The authority citation for part 192 is revised to read as follows:


11. In § 192.14, paragraph (c) is added to read as follows

§ 192.14
Conversion to service subject to this part.
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(c) An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by § 191.22 of this chapter.

12. In Section 192.175, paragraph (b) is revised to read as follows:

§ 192.175
Pipe-type and bottle-type holders.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

\[ C = \frac{3D*P*F^*}{1000} \text{ in inches; } C = \frac{3D*P*F^*}{6,895} \text{ in millimeters} \]

in which:

\[ C = \text{Minimum clearance between pipe containers or bottles in inches (millimeters).} \]

\[ D = \text{Outside diameter of pipe containers or bottles in inches (millimeters).} \]

\[ P = \text{Maximum allowable operating pressure, psi (kPa) gauge.} \]

\[ F = \text{Design factor as set forth in § 192.111 of this part.} \]

13. In § 192.225, paragraph (a) is revised to read as follows:

§ 192.225
Welding procedures.

(a) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see § 192.7), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see § 192.7) to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify welding procedures must be determined by destructive testing in accordance with the applicable welding standard(s).

14. In § 192.227, paragraph (a) is revised to read as follows:

§ 192.227
Qualification of welders.
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(a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see § 192.7), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see § 192.7). However, a welder or welding operator qualified under an earlier edition than the listed in § 192.7 of this part may weld but may not requalify under that earlier edition.

15. In § 192.631, paragraphs (b)(3) and (4) are revised, paragraph (b)(5) is added, paragraphs (h)(4) and (5) are revised, and paragraph (h)(6) is added to read as follows:

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§ 192.631

Control room management.

(b) * * *

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

(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers; and

(5) The roles, responsibilities and qualifications of others with the authority to direct or supersede the specific technical actions of a controller.

(h) * * *

(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions;
(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application; and

(6) Control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018.

16. Section 192.740 is added to read as follows:

§ 192.740
Pressure regulating, limiting, and overpressure protection—Individual service lines directly connected to production, gathering, or transmission pipelines.

(a) This section applies, except as provided in paragraph (c) of this section, to any service line directly connected to a production, gathering, or transmission pipeline that is not operated as part of a distribution system.

(b) Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every 3 calendar years, not exceeding 39 months, to determine that it is:

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Set to control or relieve at the correct pressure consistent with the pressure limits of § 192.197; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and
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(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(c) This section does not apply to equipment installed on service lines that only serve engines that power irrigation pumps.

17. Section 192.1003 is revised to read as follows:

§ 192.1003

What do the regulations in this subpart cover?

(a) General. Unless exempted in paragraph (b) of this section this subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator or a small LPG operator, must follow the requirements in §§ 192.1005 through 192.1013 of this subpart. A master meter operator or small LPG operator of a gas distribution pipeline must follow the requirements in § 192.1015 of this subpart.

(b) Exceptions. This subpart does not apply to an individual service line directly connected to a transmission, gathering, or production pipeline.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

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


19. In § 195.2, add the definitions “Confirmed discovery,” “In-Line Inspection (ILI),” “In-Line Inspection Tool or Instrumented Internal Inspection Device,” and “Significant stress corrosion cracking” in alphabetical order to read as follows:

§ 195.2

Definitions.

Confirmed Discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.
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*In-Line Inspection (ILI)* means the inspection of a pipeline from the interior of the pipe using an in-line inspection tool. Also called *intelligent or smart pigging.*

*In-Line Inspection Tool or Instrumented Internal Inspection Device* means a device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside. Also known as *intelligent or smart pig.*

*Significant Stress Corrosion Cracking* means a stress corrosion cracking (SCC) cluster in which the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 1.10% of SMYS.

20. In § 195.3:

a. Add paragraph (b)(23);
b. Revise paragraph (c)(2);
c. Redesignate paragraphs (d) through (h) as (e) through (i) respectively and add a new paragraph (d); and
d. Amend newly redesignated paragraph (g) by adding paragraphs (g)(3) and (4); and
e. Revise newly redesignated paragraph (i)(1).

The additions and revisions read as follows:

§ 195.3
Incorporation by reference.

(b) ***


(c) ***

(d) American Society for Nondestructive Testing, P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228. \textit{https://asnt.org}.


(2) [Reserved]

(g) ***


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(i) ***

(1) AGA Pipeline Research Committee, Project PR-3-805 “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,” December 22, 1989, (PR-3-805 (RSTRING)). IBR approved for §§ 195.452(h); 195.587; and 195.588(c).
21. In § 195.5, paragraph (d) is added to read as follows:

§ 195.5
Conversion to service subject to this part.

(d) An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by § 195.64.

22. In § 195.52, paragraph (a) introductory text and paragraph (d) are revised to read as follows:

§ 195.52
Immediate notice of certain accidents.

(a) Notice requirements. At the earliest practicable moment following discovery, of a release of the hazardous liquid or carbon dioxide transported resulting in an event described in § 195.50, but no later than one hour after confirmed discovery, the operator of the system must give notice, in accordance with paragraph (b) of this section of any failure that:

(d) New information. Within 48 hours after the confirmed discovery of an accident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in paragraph (b) of this section with a revised estimate of the amount of product released, location of the failure, time of the failure, a revised estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the accident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.

§ 195.64
[Amended]

23. In § 195.64, in paragraph (a), the term “hazardous liquid” is removed and replaced with the term “hazardous liquid or carbon dioxide” in the first sentence.

24. In § 195.64, paragraph (c)(1)(ii) is revised and paragraphs (c)(1)(iii) and (iv) are added to read as follows:

§ 195.64
National Registry of Pipeline and LNG operators

(c) * * *
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(1) * * *

(ii) Construction of 10 or more miles of a new or replacement hazardous liquid or carbon dioxide pipeline;

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

(iv) A pipeline converted for service under § 195.5, or a change in commodity as reported on the annual report as required by § 195.49.

25. In § 195.120, the section heading and paragraph (a) are revised to read as follows:

§ 195.120
Passage of In-Line Inspection tools.

(a) Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each replacement of line pipe, valve, fitting, or other line component in a pipeline must be designed and constructed to accommodate the passage of an In-Line Inspection tool, in accordance with NACE SP0102-2010, Section 7 (incorporated by reference, see § 195.3).

26. In § 195.214, paragraph (a) is revised to read as follows:

§ 195.214
Welding procedures.

(a) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see § 195.3), or Section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see § 195.3). The quality of the test welds used to qualify the welding procedures must be determined by destructive testing.

27. In § 195.222, paragraph (a) is revised to read as follows:

§ 195.222
Welders and welding operators: Qualification of welders and welding operators.

(a) Each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see § 195.3), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC), (incorporated by reference, see § 195.3) except that a welder or welding operator qualified under an earlier edition than listed in § 195.3, may weld but may not requalify under that earlier edition.

§ 195.248
[Amended]

28. In § 195.248, the phrase “100 feet (30 millimeters)” is removed and “100 feet (30.5 meters)” is added in its place in the table to paragraph (a).

29. In § 195.446, revise paragraphs (b)(3) and (4), add paragraph (b)(5), revise paragraphs (b)(4) and (5), and add paragraph (h)(6) to read as follows:

§ 195.446
Control room management.

(b) * * *

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

(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers; and

(5) The roles, responsibilities and qualifications of others who have the authority to direct or supersede the specific technical actions of controllers.

(h) * * *
susceptible to cracks (e.g., pipe body and weld seams), an operator must
monitor, including denting, gouging, and grooving. For pipeline segments that are
suitable in-line inspection tool or tools capable of detecting corrosion and deformation

(a) In-line Inspection Tool or Tools Capable of Detecting Corrosion and Deformation

(1)

(2)

(3)

(4) Low Stress Pipelines as specified in § 195.12.

(b) Pipeline Integrity Management in High Consequence Areas

§ 195.452

as follows:

30. In § 195.452, paragraphs (a)(4) is added and paragraphs (c)(1)(l)(A) and (c)(1)(l)(f) are revised to read:

This paragraph no later than January 23, 2018, conformsity standard. Operators must comply with the team training requirements under

collaborate with controllers (control room personnel) during normal, abnormal, or

individuals defined by the operator, who would reasonably be expected to operate

(6) Control room team training and exercises that include both controllers and other

and

operators for controllers to review relevant procedures in advance of their application;

(5) For pipeline operating setups that are periodically, put intentionally used, providing an

especially during the development of abnormal operating conditions;

(4) Training that will provide a controller with knowledge of the pipeline system;

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use an in-line inspection tool or tools capable of detecting crack anomalies. When performing an assessment using an In-Line Inspection Tool, an operator must comply with § 195.591;

(j) ***

(5) ***

(i) In-Line Inspection tool or tools capable of detecting corrosion and deformation anomalies, including dents, gouges, and grooves. For pipeline segments that are susceptible to cracks (pipe body and weld seams), an operator must use an in-line inspection tool or tools capable of detecting crack anomalies. When performing an assessment using an In-Line Inspection tool, an operator must comply with § 195.591;

31. In § 195.588, paragraph (a) is revised and paragraph (c) is added to read as follows:

§ 195.588
What standards apply to direct assessment?

(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion or stress corrosion cracking, you must follow the requirements of this section. This section does not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

(c) If you use direct assessment on an onshore pipeline to evaluate the effects of stress corrosion cracking, you must develop and follow a Stress Corrosion Cracking Direct Assessment plan that meets all requirements and recommendations of NACE SP0204-2008 (incorporated by reference, see § 195.3) and that implements all four steps of the Stress Corrosion Cracking Direct Assessment process including pre-assessment, indirect inspection, detailed examination and post-assessment. As specified in NACE SP0204-2008, Section 1.1.7, Stress Corrosion Cracking Direct Assessment is complementary with
other inspection methods such as in-line inspection or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data to identify whether the conditions for stress corrosion cracking are present and to prioritize the segments for assessment in accordance with NACE SP0204-2008, Sections 3 and 4, and Table 1. This process must also include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204-2008 indicate the potential for Stress Corrosion Cracking Direct Assessment. This data gathering process must be conducted in accordance with NACE SP0204-2008, Section 5.3, and must include, at a minimum, all data listed in NACE SP0204-2008, Table 2. Further, an operator must analyze the following factors as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment such as soil temperature, moisture, factors that affect the rate of carbon dioxide generation, and/or cathodic protection.

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments.

(iii) The effects of variations in applied cathodic protection such as overprotection, cathodic protection loss for extended periods, and high negative potentials.

(iv) The effects of coatings that shield cathodic protection when disbonded from the pipe.

(v) Other factors that affect the mechanistic properties associated with SCC including but not limited to operating pressures, high tensile residual stresses, and the presence of sulfides.
(2) Indirect inspection. In addition to the requirements and recommendations of NACE SP0204-2008, Section 4, the plan's procedures for indirect inspection must include provisions for conducting at least two different, but complementary, indirect assessment electrical surveys, and the basis on the selections as the most appropriate for the pipeline segment based on the data gathering and integration step.

(3) Direct examination. In addition to the requirements and recommendations of NACE SP0204-2008, Section 5, the plan's procedures for direct examination must provide for conducting a minimum of four direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

(4) Remediation and mitigation. If any indication of SCC is discovered in a segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Non-significant SCC, as defined by NACE SP0204-2008, may be mitigated by either hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section, or by grinding out with verification by Non-Destructive Examination (NDE) methods that the SCC defect is removed and repairing the pipe. If grinding is used for repair, the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG (incorporated by reference, see § 195.3) and must be sufficient to meet the design requirements of subpart C of this part.

(ii) Significant SCC must be mitigated using a hydrostatic testing program with a minimum test pressure between 100% up to 110% of the specified minimum yield strength for a 30-minute spike test immediately followed by a pressure test in accordance with subpart E of this part. The test pressure for the entire sequence must be continuously maintained for at least 8 hours, in accordance with subpart E of this part. Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment retested until the pipe passes the complete test without leakage. Pipe segments that have SCC present, but that pass the pressure test, may be repaired by grinding in accordance with paragraph (c)(4)(i) of this section.
(5) Post assessment. In addition to the requirements and recommendations of NACE SP0204-2008, sections 6.3, periodic reassessment, and 6.4, effectiveness of Stress Corrosion Cracking Direct Assessment, the plan's procedures for post assessment must include development of a reassessment plan based on the susceptibility of the operator's pipe to Stress Corrosion Cracking as well as on the behavior mechanism of identified cracking. Factors to be considered include, but are not limited to:

(i) Evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204-2008, sections 5.3.5.7, 5.4, and 5.5;

(ii) Conditions conducive to creation of the carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of cathodic protection that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions;

(v) Cyclic loading conditions;

(vi) Conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and

(ix) Disbonded coatings that shield CP from the pipe.

32. Section 195.591 is added to read as follows:

§ 195.591
In-Line inspection of pipelines.

When conducting in-line inspection of pipelines required by this part, each operator must comply with the requirements and recommendations of API Std 1163, Inline Inspection Systems Qualification Standard; ANSI/ASNT ILI-PQ, Inline Inspection Personnel
Qualification and Certification; and NACE SP0102-2010, Inline Inspection of Pipelines (incorporated by reference, see § 195.3). An in-line inspection may also be conducted using tethered or remote control tools provided they generally comply with those sections of NACE SP0102-2010 that are applicable.

PART 199—DRUG AND ALCOHOL TESTING

33. The authority citation for part 199 continues to read as follows:


34. In § 199.105, paragraph (b) is revised to read as follows:

§ 199.105
Drug tests required.

(b) Post-accident testing. (1) As soon as possible but no later than 32 hours after an accident, an operator must drug test each surviving covered employee whose performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. An operator may decide not to test under this paragraph but such a decision must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident.

(2) If a test required by this section is not administered within the 32 hours following the accident, the operator must prepare and maintain its decision stating the reasons why the test was not promptly administered. If a test required by paragraph (b)(1) of this section is not administered within 32 hours following the accident, the operator must cease attempts to administer a drug test and must state in the record the reasons for not administering the test.

35. In § 199.117, paragraph (a)(5) is added to read as follows:

§ 199.117
Recordkeeping.

(a) * * *

(5) Records of decisions not to administer post-accident employee drug tests must be kept for at least 3 years.
36. In § 199.119, paragraphs (a) and (b) are revised to read as follows:

§ 199.119
Reporting of anti-drug testing results.

(a) Each large operator (having more than 50 covered employees) must submit an annual Management Information System (MIS) report to PHMSA of its anti-drug testing using the MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40), not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (https://portal.phmsa.dot.gov/phmsaportallanding) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA.

(b) Each report required under this section must be submitted electronically at http://damis.dot.gov. An operator may obtain the user name and password needed for electronic reporting from the PHMSA Portal (https://portal.phmsa.dot.gov/phmsaportallanding). If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

37. In § 199.225, the introductory text and paragraph (a)(1) are revised to read as follows:

§ 199.225
Alcohol tests required.

Each operator must conduct the following types of alcohol tests for the presence of alcohol:
CHANGES BY SPECIFIC CITATION RECENT FINAL RULEMAKING

Effective Date:
03/24/2017

(a) * * *

(1) As soon as practicable following an accident, each operator must test each surviving covered employee for alcohol if that employee's performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. The decision not to administer a test under this section must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident.

38. In § 199.227, paragraph (b)(4) is added to read as follows:

§ 199.227
Retention of records.

(b) * * *

(4) Three years. Records of decisions not to administer post-accident employee alcohol tests must be kept for a minimum of three years.

39. In § 199.229, paragraphs (a) and (c) are revised as follows:

§ 199.229
Reporting of alcohol testing results.

(a) Each large operator (having more than 50 covered employees) must submit an annual MIS report to PHMSA of its alcohol testing results using the MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40), not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (https://portal.phmsa.dot.gov/phmsaportallanding) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA.

(c) Each report required under this section must be submitted electronically at http://damis.dot.gov. An operator may obtain the user name and password needed for electronic reporting from the PHMSA Portal (https://portal.phmsa.dot.gov/).
CHANGES BY SPECIFIC CITATION RECENT FINAL RULEMAKING

Effective Date:
03/24/2017

If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative Start Printed Page 8002reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

NOTE:
PHMSA is delaying final action on the provisions regarding (1) OQ scope and definitions as they were proposed at §§ 192.801 and 192.803 under subpart N for the natural gas pipeline regulations and at §§ 195.501 and 195.503 for subpart G for the hazardous liquid pipeline regulations, respectively; (2) qualification programs as they were proposed at §§ 192.805 and 195.505 for the natural gas pipeline regulations and the hazardous liquid pipeline regulations, respectively; (3) OQ program effectiveness as they were proposed at §§ 192.807 and 195.507 for the natural gas pipeline regulations and the hazardous liquid pipeline regulations, respectively; and (4) OQ recordkeeping as they were proposed at §§ 192.809 and 195.509 for the natural gas pipeline regulations and the hazardous liquid pipeline regulations, respectively.
PHMSA notes that revised OQ requirements will be published in a subsequent final rule in the near future, and it will consider and discuss, at length, all of the comments received for each of the topic areas listed above along with the recommendations of the Pipeline Advisory Committees, in that final rulemaking.