

(1) Determine the largest defect most likely to remain in the segment and the corrosion rate appropriate for the pipe, soil and protection conditions.

(2) Take the largest remaining defect as the size of the largest defect discovered in the ECDA or ICDA segment.

(3) *Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.*

(B) However, the reassessment interval cannot exceed five (5) years, if an operator directly examines and remediates defects by sampling, or ten (10) years, if an operator conducts a direct examination of all anomalies and remediates these anomalies.

(4) *Waiver from interval greater than 7 years in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval greater than seven years but within the maximum allowable interval if OPS finds a waiver would not be inconsistent with pipeline safety.

(i) *Lack of internal inspection tools.* An operator may be able to justify a longer assessment period for a covered segment if internal inspection tools are not available to assess the line pipe. An operator must demonstrate that the internal inspection tools cannot be obtained within the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must, in accordance with paragraph (n) of this section, notify OPS 180 days before the end of the required reassessment interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed.

(ii) *Maintain local product supply.* An operator may be able to justify a longer assessment period for a covered segment if the operator demonstrates that the reassessment will shut off the local product supply, and that alternative supply is not available. An operator must, in accordance with paragraph (n) of this section, notify OPS 180 days before the end of the required reassessment interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed.

(5) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe by any of the following methods.

(i) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the pipe segment is susceptible. An operator must follow ASME/ANSI B31.8S, section 6.2, in

selecting the appropriate internal inspection tools;

(ii) Pressure test conducted in accordance with subpart J of this Part;

(iii) Direct assessment to address threats of external corrosion threats, internal corrosion, and stress corrosion cracking that is conducted in accordance with ASME/ANSI B31.8S section 6.3, and paragraph (h) of this section;

(iv) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with paragraph (n) of this section.

(v) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with paragraph (h)(6) of this section.

(1) *What methods must be used to measure program effectiveness?* (1) *General.* An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S, Section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix SP-A. An operator must make the four overall performance measures accessible in real time to OPS and state pipeline safety enforcement officials.

(2) *Direct assessment.* In addition to the general requirements for performance measures, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of paragraph (h)(3)(vii) of this section.

(m) *What records must be kept?* An operator must maintain for review during an inspection—

(1) A written baseline assessment plan in accordance with paragraphs (e) and (g) of this section;

(2) A written integrity management program in accordance with the requirements of this section.

(3) Documents to support the decisions, analyses and processes developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents

include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.

(4) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with paragraph (d)(2) of this section.

(5) Documents to carry out the requirements in paragraph (h) of this section for a direct assessment plan.

(6) Documents demonstrating the integrity management program has been provided to the interstate agent, and that any safety concerns raised by OPS on behalf of an interstate agent have been addressed.

(n) *How does an operator notify OPS?* An operator must provide notification required by this section by—

(1) Sending the notification to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW., Washington DC 20590;

(2) Sending the notification by facsimile to (202) 366-7128; or

(3) Entering the information directly on the Integrity Management Database (IMDB) Web site at <http://primis.rspa.dot.gov/imdb/>.

3. Appendix A to Part 192, section II.D would be amended by adding paragraph (9) to read as follows:

Appendix A to Part 192—Incorporated by Reference

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II. * * *

D. * * *

(9) ASME/ANSI B31.8S 2001 Supplement to B31.8 on Managing System Integrity of Gas Pipelines, January 31, 2002.

4. A new Appendix E to Part 192 would be added to part 192 to read as follows:

Appendix E to Part 192

I. Guidance on Determining a Potential Impact Zone Within a High Consequence Area

Within each high consequence area, an operator is to calculate the potential impact zone. (Refer to figure E.I.1 for the diagram of a potential impact zone) High consequence areas and potential impact zone are defined in § 192.761. The potential impact zone will help an operator determine the area where segments must be given priority for assessment.