**DEPARTMENT OF TRANSPORTATION**

**Research and Special Programs Administration**

**49 CFR Part 192**

**[Docket No. RSPA–00–7666; Amendment 192–95]**

**RIN 2137–AD54**

# Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines); Correction

**AGENCY:** Office of Pipeline Safety (OPS), Research and Special Programs Administration (RSPA), DOT.

**ACTION:** Final rule; correction & petition for reconsideration.

**SUMMARY:** This document corrects a final rule published in the **Federal Register** on December 15, 2003 (68 FR 69778). That rule requires operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm, *i.e.*, could impact high consequence areas (HCAs). The rule requires gas transmission pipeline operators to perform ongoing assessments of pipeline integrity, to improve data collection, integration, and analysis, to remediate the pipeline as necessary, and to implement additional preventive and mitigative actions. This document makes minor editorial corrections and clarifies the intent of several provisions in the rule. This document also addresses a petition for reconsideration filed by the Interstate Natural Gas Association of America (INGAA).

**EFFECTIVE DATE:** The effective date is April 6, 2004.

**FOR FURTHER INFORMATION CONTACT:** Mike Israni by phone at (202) 366–4571, by fax at (202) 366–4566, or by e-mail at *mike.israni@rspa.dot.gov,* regarding the subject matter of the final rule.

**SUPPLEMENTARY INFORMATION:**

## Background

On December 15, 2003, RSPA/OPS published a final rule (68 FR 69778) that requires operators of gas transmission pipelines to develop and implement a comprehensive integrity management program for pipeline segments where a failure would have the greatest impact to the public or property.

### *Errors and Language in the Rule Needing Correction or Clarification*

OPS has identified errors in the published final rule (68 FR 69778; December 15, 2003), such as incorrect reference numbers, editorial errors, incorrect terms and misspellings. OPS has also identified language in several provisions of the rule that is confusing and needs clarification. Thus, this document either corrects the rule because of mistakes found since the rule was published or clarifies the language and intent of the rule. None of these substantively changes any requirement in the rule.

### *Petition for Reconsideration*

On January 15, 2004, the Interstate Natural Gas Association of America (INGAA) filed a petition for reconsideration of the final rule on gas integrity management identifying corrections INGAA believed were needed in the rule. This document addresses that petition. This document addresses mistakes the petitioner has identified in the rule and clarifies ambiguous language the petitioner identified. However, this document does not address what INGAA identified as mistakes but that would substantively change the rule. (See section below titled "Recommended changes not made'').

### *Corrections and Clarifications*

Section 192.901 states that the integrity management program regulations apply to gas transmission pipelines. In the Preamble to the final rule, we stated our intent that the integrity management program requirements apply to gas transmission pipelines and not to gas gathering or distribution lines. However, § 192.9 provides that except for the requirements in §§ 192.1 and 192.150, operators of gathering lines must follow the requirements for transmission pipelines. We have clarified in § 192.9 that gathering lines are not subject to the requirements of subpart O. This clarification is to ensure that there is no misunderstanding about which gas pipelines the integrity management program requirements are intended to apply.

The final rule includes a definition for identified sites in § 192.903. One component of this definition is any building that is occupied by 20 or more persons for specified periods and that meets other specified criteria. The rule language is correct. However, in the preamble of the final rule, we incorrectly described the component as "buildings housing 50 or more people.'' The preamble discussion should have said "buildings housing 20 or more people'' to match the rule requirement.

Section 192.903 included allowed an operator to choose one of two methods for identifying a high consequence area. Method 1 involves designating all class 3 and 4 areas as high consequence areas, and was intended to relieve operators from the need to calculate and evaluate potential impact circles in these areas. We intended, however, that an operator would have to calculate and evaluate potential impact circles on any transmission pipeline not in a class 3 or class 4 area. We used the phrase "outside a Class 3 or Class 4 location'' to describe these high consequence areas. However, this phrase could be interpreted to include areas more than 660 feet from a pipeline where the pipeline is in a class 3 or 4 area. We did not intend for an operator to evaluate any areas further than 660 feet from the pipeline in these areas, since the pipeline is already in a high consequence area under the criteria of method 1. We replaced this phrase with "in a Class 1 or Class 2 location'' to make it clear that we are referring to an evaluation of pipeline segments not already classified as high consequence areas.

In addition, another criterion under method 1 refers to potential impact circles containing an identified site, which again could be interpreted as requiring operators to calculate potential impact circles within existing class 3 and 4 areas. We have revised this criterion (paragraph (1)(iv)) to clarify that the evaluation need only be performed in class 1 and 2 areas, where the existence of an identified site might require that the area be considered a high consequence area.

Several provisions in the rule require notification to OPS and in some instances to a State pipeline safety authority when a State acts as an interstate agent on a covered segment of transmission pipeline or the State regulates a covered segment on an intrastate transmission pipeline. The language requiring the state notification was confusing. We have clarified the language.

The Preamble discussed the necessity of keeping state regulators informed versus the need to keep an operator's information about its system secure. Where security of information was a concern, we limited the information submission to OPS or to an interstate agent, as the statute required. Where security was not an issue, the rule included state notification on an intrastate transmission line regulated by the State. However, in two provisions on notification when an operator uses other technology to assess a covered segment for the baseline or reassessment (§§ 192.921(a)(4) and 192.937(c)(4)), we inadvertently left out the notification to a State when it is either an interstate agent or regulates an intrastate transmission covered segment. We have corrected these omissions.

Section 192.913 of the final rule establishes conditions under which an operator may deviate from specific provisions of the rule, by establishing a performance-based program. One of the required criteria is that an operator have completed at least two integrity assessments on all covered pipeline segments (§ 192.913(b)(2)(i)). This was a mistake. The rule should have limited the prior integrity assessment to those segments the operator wants to include under the performance-based option. We have revised the criterion to require that at least two assessments must have been completed on all segments to be included in the operator's performance-based program. This change clarifies that an operator may establish a performance-based program covering only a portion of its pipeline segments subject to the final rule. The remaining covered segments would still be subject to the more prescriptive approach.

In § 192.917, paragraph (a) lists the types of threats an operator is to consider in its threat identification. We have revised the paragraph to clarify that the threats listed in the rule restate the threats listed in the ASME/ANSI B31.8S standard, and are not in addition to those in the standard.

In § 192.917, paragraph (b) requires an operator to gather and integrate data from its entire pipeline system that could be relevant to identifying potential threats to the covered pipeline segment. Although it seems self-evident that an operator must only gather and integrate existing data about its pipeline system, industry has expressed concern that an operator will be required to create data. We have revised the paragraph to clarify that the data has to exist before it is gathered and integrated for analysis.

In § 192.917, paragraph (e) requires an operator to analyze its pipeline to identify specific potential threats to the pipeline. This document revises two paragraphs in this section (paragraphs (e)(1) and (e)(3)) to provide additional clarity on information that must be included in these analyses. Paragraph (e)(1) now specifies that an operator is to use information from a direct assessment to help define where third party damage may exist. Similarly, paragraph (e)(3) now specifies that an operator is to use information from prior integrity assessments to determine the risk of failure in the covered segment from manufacturing and construction defects.

In § 192.917, paragraph (e)(3) also establishes requirements specific to pipe for which an operator has identified the threat of manufacturing and construction defects. This paragraph states that an operator may consider such defects to be stable defects if the operating conditions on the covered segment have not changed significantly "since December 17, 1998.'' We intended this provision to provide for a retrospective evaluation of five years, beginning from the date on which integrity management requirements were first established by the Pipeline Safety Improvement Act of 2002. These requirements would also apply, however, for pipeline in areas which may be identified as high consequence areas many years in the future. For such pipe, a retrospective evaluation reaching back to 1998 would not make sense. This paragraph has been revised to require that the retrospective evaluation cover 5 years, regardless of when the high consequence area is identified.

In § 192.917, paragraph (e)(4) establishes requirements specific to low-frequency electric resistance welded (ERW) pipe and lap welded pipe that satisfies conditions in an industry standard, ASME/ANSI B31.8S. The rule incorporates by reference the industry standard. The preamble to the final rule stated that these requirements would apply to pipe that has a history of seam failures. However, this criterion was inadvertently omitted from the rule. We have added the criterion with additional clarification. We have clarified that when a covered pipe segment has low frequency ERW pipe, lap welded or other pipe that satisfies the conditions in ASME B31.8S, Appendices A.4.3 and A4.4, and any such pipe in the system has a history of seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, the operator must prioritize the covered segment as a high risk segment for assessment purposes and must use a specified type of assessment technology. We have also clarified the capabilities that are required of the assessment technology.

In § 192.921, paragraph (a)(2) requires that a pressure test used for the baseline assessment of a covered pipeline segment must be conducted in accordance with subpart J of part 192. The test pressures required by subpart J, while adequate to demonstrate the segment's integrity, are lower than required to justify some of the reassessment intervals under § 192.939. To avoid confusion, we have added a sentence providing that higher test pressures that are in accordance with Table 3 of Section 5 of ASME/ANSI B31.8S may be needed to justify an extended reassessment interval under § 192.939.

In § 192.921, paragraph (g) requires that an assessment be completed for newly-installed pipe within ten years from when the pipe is installed. This paragraph allows a pressure test, meeting the requirements of 49 CFR part 192, subpart J, which would normally be conducted as part of installation, to be used to meet this requirement. The reference to this pressure test in the final rule referred to it as a post-installation test. That term was incorrect because subpart J allows reliance on tests conducted prior to installation. There is no technical reason to deviate from the established subpart J requirements, and the final rule has been changed to delete the term post-installation.

Section 192.925 sets forth the requirements for external corrosion direct assessment. The threat identification section (§ 192.917) requires operators to take actions to address particular threats. One of these threats is third-party damage. The data from a direct assessment can be relevant to identifying this damage, such as identifying coating damage that may indicate damage from a third party excavation. In § 192.925 we are adding a sentence to clarify that operators are to integrate data from the external corrosion direct assessment with data from internal inspection tools and other information relevant to the pipeline to help identify and address third-party damage.

In § 192.927, paragraph (b) includes requirements for the internal corrosion direct assessment (ICDA) process for the dry gas system. If an operator uses ICDA to assess a segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion. This ICDA application would be other technology that requires notification to OPS and to the State pipeline safety authority, when applicable. We have clarified that an operator using ICDA for a wet gas system must provide this required notification.

In § 192.927, paragraph (c)(3) includes criteria to identify locations where direct examination of the pipe must be conducted when an operator is using ICDA. These criteria specified a minimum of two direct examinations, one of which must be at the low spot within the covered segment nearest to the beginning of the ICDA region and the second "at the upstream end of the pipe containing a covered segment, having a slope not exceeding the critical angle of inclination nearest the end of the ICDA region.'' The wording of the second required location has caused confusion. We have clarified the language to specify that the second location be " farther downstream within a covered segment near the end of the ICDA Region.'' There is no technical difference in this change; the revised wording more clearly describes the requirement.

In § 192.927, paragraph (c)(4)(i) requires that operators using internal corrosion direct assessment (ICDA) evaluate its effectiveness as an assessment method and in determining whether more frequent reassessments are required. In the final rule, this paragraph required that this evaluation be done "in the same year in which ICDA is used.'' This could be unnecessarily burdensome, or even impractical, for situations in which ICDA is used late in a calendar year, as it would essentially require that the evaluations be performed immediately. This was not intended. This requirement has been revised to specify that the evaluation be carried out within a year of conducting the ICDA.

In § 192.933, paragraph (b) specifies that discovery of a condition is considered to occur when an operator has adequate information to determine that the condition "presents a potential threat to the integrity of the pipeline.'' As we explained in the Preamble to the final rule (68 FR 69797–98), adequate information to make this determination includes information that the condition is one included in ASME/ANSI B31.8S as needing a response. To further clarify the types of conditions that might be potential threats to a system's integrity we have added a sentence that explains that a potential threat includes the immediate repair, one-year and monitored conditions listed in the rule. The rule does not list all conditions that might present a potential threat but gives examples of those that are most common. Although a monitored condition does not present an immediate threat or need remediation within a year, it is a condition that presents a potential threat because a change could occur making the threat to the pipeline's integrity more immediate.

To protect against third-party damage, paragraph (b)(1)(iv) of § 192.935 requires an operator to monitor excavations near its pipelines or investigate when the operator finds evidence of any excavation it did not monitor. Although not intended, this paragraph could be read as requiring an operator to investigate (*i.e.*, excavate or conduct above ground measurements) whenever the operator finds evidence of encroachment involving excavation, even if the operator had monitored the excavation. This paragraph has been revised to reflect our intent that the investigation be limited to instances when the operator did not monitor the excavation.

In § 192.935, paragraph (d) specifies requirements for additional preventive and mitigative measures for a pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area. Although the guidance table in appendix E had included measures to address external and internal corrosion threats, and additional preventive and mitigative measures for a pipeline operating below 30% SMYS located in a high consequence area, we did not include these measures in the rule language itself. We have added these measures to the rule.

In § 192.937, paragraph (c)(2) specifies that a pressure test used to reassess a covered pipeline segment must be conducted in accordance with Subpart J of Part 192. This reference to subpart J is revised to include Table 3 of Section 5 of ASME/ANSI B31.8S, for the reasons given in § 192.921(a)(2) above.

In § 192.939, paragraph (a) specifies reassessment intervals for a pipeline operating at or above 30% SMYS and paragraph (b) specifies reassessment intervals for a pipeline operating below 30% SMYS. Both paragraphs state that the minimum reassessment interval is seven years. This has been corrected now to state that the maximum reassessment interval is seven years.

In § 192.945, paragraph (a) requires an operator to include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures include the four overall performance measures and the specific measures for each identified threat specified in ASME/ANSI B31.8S, appendix A. RSPA/OPS had intended that an operator submit only the four overall performance measures, by electronic or other means, on a semi-annual frequency. The additional measures are to be reviewed during inspections. However, the final rule mistakenly requires all measures to be submitted semi-annually. We have corrected paragraph (a) to specify that an operator submit the four overall performance measures semi-annually. In addition, we have included the dates by which an operator is to submit these semi-annual performance measures. Similarly, our intent was that performance measures related to external corrosion direct assessment were to be reviewed during inspection, not submitted to OPS. Accordingly, we have removed the requirement in paragraph (b) that these measures be submitted semi-annually.

Some of the examples in section I of appendix E that illustrate the methods for identifying high consequence areas are inconsistent with the definition in § 192.903. We have deleted the examples to avoid any confusion about the definition. The illustrative figure in this appendix, Figure E.I.A, is accurate, and has been retained.

Section II of appendix E provides additional guidance for operators on assessment methods and additional preventive and mitigative measures. Some, but not all, of the guidance in this appendix is applicable to pipelines operating below 30% SMYS. However, the title of the appendix incorrectly states that the guidance is only for assessment methods and applies only to pipelines operating below 30% SMYS. This is being corrected. The paragraphs in this appendix that refer to Tables E.II.1 and E.II.2 are also corrected to more accurately describe the information in those tables.

Table E.II.1, in appendix E, describes additional preventive and mitigative measures that must be taken for pipelines in class 3 or class 4 areas but not in high consequence areas. The title of the table and the heading for column 4 inaccurately refer to assessment methods, which are not described in this table. We have corrected the title and column heading.

*Recommended Changes Not Made*

In the petition for reconsideration of the final rule, several of the changes INGAA recommended are substantive changes to the final rule. The recommended changes were neither errors we had made in drafting the rule nor language we believe needs clarification. We have not made these changes because they do not reflect our intent and would substantively change the intent of the rule. Specifically, we have not included the following changes in this document.

- In § 192.913(b)(2)(ii), we have not changed the word "anomalies'' to "defects''. We use the word "anomalies'' throughout the rule.
- In § 192.917(a), we have not deleted the description of the four types of general threats an operator must identify. INGAA noted that this listing is redundant to the descriptions in ASME/ANSI B31.8S. We consider the nature of these threats as key to

understanding the rule; therefore, the listing should be included in the rule. As we described above, we have clarified the language in this section to correct any impression that the described threats are in addition to those in the standard.

- In § 192.917(b), we have not, as INGAA suggested, substituted "similar segments'' for the word "entire'' in the requirement that an operator gather and integrate information on its entire pipeline system that could be relevant to the covered segment. A crucial element of integrity management is the integration of relevant information from the entire system, not just from certain segments of the system.
- In § 192.921(e), we have not adopted the suggestion that a prior assessment done before December 17, 2002 substantially meet the baseline requirements for the prior assessment to qualify as a baseline assessment. We believe that what constitutes substantial compliance is too subjective. There would be constant disagreement between operators and regulators about what substantial compliance means. We allowed more flexible requirements for a prior assessment under the performance-based option because that option sets additional and more stringent requirements. Those additional requirements are not present when a prior assessment is used under the non performance-based approach. Furthermore, to give operators flexibility in the use of prior assessments, in the final rule we deleted the proposed requirement that set a five-year period before December 17, 2002 and allowed any prior assessment before December 17, 2002 so long as it meets certain requirements.
- In § 192.927(c)(5)(iii), we have not deleted the word "entire'' from the requirement that an operator's internal corrosion direct assessment plan provide for an analysis carried out on the entire pipeline in which covered segments are present.
- In § 192.937(b), we have not deleted the word "entire'' from the requirement that an operator conduct a periodic evaluation that is based on a data integration and risk assessment of the entire pipeline.
- Several provisions in the rule differentiate requirements based on whether a transmission pipeline is operating below 30% SMYS, operating at or above 30% SMYS up to 50% SMYS or operating at or above 59% SMYS. We have not changed the categories. However, we recognize that these categories are changed in the draft 2004 version of the ASME B31.8S standard. Once that standard is finalized and if we adopt it into the rule, then we will change the stress classifications.
- We have not moved the notification procedures in §§ 192.941 and 192.951 to Part 191. These procedures are specific to notification for integrity management program purposes.

**List of Subjects in 49 CFR Part 192**

High consequence areas, Incorporation by reference, Integrity management, Pipeline safety, Potential impact areas, Reporting and recordkeeping requirements.

## PART 192—[AMENDED]

■ Accordingly, 49 CFR part 192 is corrected by making the following correcting amendments:

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

**Authority:** 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, and 60118; and 49 CFR 1.53.

■ 2. Section 192.9 is revised to read as follows:

### § 192.9 Gathering lines.

Except as provided in §§ 192.1 and192.150, and in subpart O, each operator of a gathering line must comply with the requirements of this part applicable to transmission lines.

* * * * *

■ 3. Section 192.903 is amended as follows:

■ a. In the definition of "Assessment'', the word "nondestructive'' is removed;

■ b. In the definition of "Confirmatory direct assessment'', the word "integrity'' is added in the first sentence before the words "assessment method'';

■ c. The definition of "High consequence area'' is revised; and

■ d. The definition of "Identified site'' is amended by removing '')'' at the end of paragraphs (a) and (b).

The additions and revisions read as follows:

### § 192.903 What definitions apply to this subpart?

* * * * *

*High consequence area* means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under § 192.5; or

(ii) A Class 4 location under § 192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact radius contains an identified site.

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph

(4) applies; or

(ii) An identified site.

* * * * *

■ 4. Section 192.909 is amended by revising paragraph (b) to read as follows:

### § 192.909 How can an operator change its integrity management program?

* * * * *

(b) *Notification.* An operator must notify OPS, in accordance with § 192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

* * * * *

### § 192.911 [Amended]

■ 5. In § 192.911, paragraph (i) is amended by removing "§ 192.943'' and adding "§ 192.945'' in its place.

■ 6. In § 192.913:

■ a. Paragraph (b)(1) (vii) is amended by removing "§ 192.943'' and adding "§ 192.945'' in its place; and

■ b. Paragraph (b)(2)(i) is revised to read as follows:

### § 192.913 When may an operator deviate its program from certain requirements of this subpart?

* * * * *

(b) * * *

(2) * * *

(i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.

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■ 7. In § 192.917:

■ a. Paragraph (a) introductory text is revised;

■ b. Paragraph (b) is revised;

■ c. Paragraphs (e)(1), (e)(3) and (e)(4) are revised; and

■ d. Paragraph (e)(5) is amended by removing "§ 192.931'' and adding "§ 192.933'' in its place.

The revisions read as follows:

**§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (ibr, see § 192.7), section 2, which are grouped under the following four categories:

* * * * *

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

* * * * *

(e) * * *

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with § 192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under § 192.921, or a reassessment under § 192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) * * *

(3) *Manufacturing and construction defects.* If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

* * * * *

■ 8. In § 192.921:

■ a. Paragraphs (a)(2) and (a)(4) are revised;

■ b. Paragraph (c) is amended by removing "§ 192.917(d)'' and adding "§ 192.917(e)'' in its place;

■ c. Paragraph (f) is amended by removing "§ 192.205'' and adding "§ 192.905'' in its place; and

■ d. Paragraph (g) to revised.

The revisions read as follows:

**§ 192.921 How is the baseline assessment to be conducted?**

(a) * * *

(1) * * *

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with § 192.939.

(3) * * *

(4) 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 § 192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

* * * * *

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

* * * * *

■ 9. Section 192.925 is amended by revising paragraph (b) to read as follows:

**§ 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?**

* * * * *

(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (ibr, see § 192.7), section 6.4, and in NACE RP 0502–2002 (ibr, see § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§ 192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by § 192.917(e)(1).

* * * * *

■ 10. Section 192.927 is amended by revising paragraphs (b), (c)(3) introductory text and (c)(4)(i) to read as follows:

**§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?**

* * * * *

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ANSI B31.8S (ibr, see § 192.7), section 6.4 and appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with § 192.921 (a)(4) or § 192.937(c)(4).

(c) * * *

(3) *Identification of locations for excavation and direct examination.* An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must—

(4) * * *

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. An operator must carry out this evaluation within a year of conducting an ICDA; and

* * * * *

■ 11. Section 192.929 is amended by revising paragraph (a) to read as follows:

**§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?**

(a) *Definition.* Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

* * * * *

■ 12. Section 192.933 is amended by revising paragraphs (b), (c) and (d)(1)(iii) to read as follows:

**§ 192.933 What actions must be taken to address integrity issues?**

* * * * *

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (ibr, see § 192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify OPS in accordance with § 192.949 if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(d) * * *

(1) * * *

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

* * * * *

■ 13. In § 192.935:

■ a. The section heading of § 192.935 is revised;

■ b. Paragraphs (b)(1) introductory text, (b)(1)(ii), and (b)(1)(iv) are revised; and

■ c. Paragraph (d) introductory text is revised and paragraph (d)(3) is added.

■ The additions and revisions are as follows:

**§ 192.935 What additional preventive and mitigative measures must an operator take?**

* * * * *

(b) * * *

(1) *Third party damage.* An operator must enhance its damage prevention program, as required under § 192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(i) * * *

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) * * *

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP–0502–2002 (ibr, see § 192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and § 192.933 any indication of coating holidays or discontinuity warranting direct examination.

* * * * *

(d) *Pipelines operating below 30% SMYS.* An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2)of this section, the requirements for a low stress external corrosion reassessment in § 192.941(b) and the requirements for a low stress internal corrosion reassessment in § 192.941(c). An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

(1) * * *

(2) * * *

(3) Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).

* * * * *

■ 14. Section 192.937 is amended by revising paragraphs (c)(2) and (c)(4) to read as follows:

**§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?**

* * * * *

(c) * * *

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with § 192.939.

(3) * * *

(4) 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 § 192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

* * * * *

■ 15. In § 192.939:

■ a. Paragraphs (a) introductory text and (a)(1)(i) are revised;

■ b. Paragraph (a)(3) is amended by removing the word "calculation'' at the end of the first sentence and adding the word "method'' in its place;

■ c. Paragraph (b) introductory text is amended by removing the word "minimum'' in the beginning of the second sentence and adding the word "maximum'' in its place; and

■ d. Paragraph (b)(5) is revised and the undesignated paragraph before the table is designated as paragraph (b)(6).

■ The revisions read as follows:

**§ 192.939 What are the required reassessment intervals?**

* * * * *

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

(1) * * *

(i) Basing the interval on the identified threats for the covered segment (see § 192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by § 192.917; or

* * * * *

(b) * * *

(5) Reassessment by the low stress assessment method at 7-year intervals in accordance with § 192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

The following table sets forth the maximum reassessment intervals. Also refer to Appendix E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

* * * * *

**§ 192.941 [Amended]**

■ 16. In § 192.941, paragraph (b)(2)(ii) is amended by removing the term "1½ years'' in the first sentence and adding "18 months'' in its place.

■ 17. Section 192.943 is amended by revising paragraph (a)(1) to read as follows:

**§ 192.943 When can an operator deviate from these reassessment intervals?**

* * * * *

(a) * * *

(1) *Lack of internal inspection tools.* An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

* * * * *

■ 18. Section 192.945 is amended as follows:

■ a. Paragraph (a) to revised; and

■ b. Paragraph (b) is amended by removing the last sentence.

**§ 192.945 What methods must an operator use to measure program effectiveness?**

(a) *General.* An operator must include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (ibr, see § 192.7), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with § 192.951. An operator must submit its first report on overall performance measures by August 31, 2004. Thereafter, the performance measures must be complete through June 30 and December 31 of each year and must be submitted within 2 months after those dates.

* * * * *

**§ 192.947 [Amended]**

■ 19. In § 192.947 second sentence is amended by removing "minium'' and adding "minimum'' in its place.

**Appendix A to Part 192 [Amended]**

■ 20. Appendix A to part 192 is amended by redesignating paragraph numbers II. F. and II. G. as paragraph numbers II. H. and II. I., respectively.

■ 21. Appendix E to part 192 is revised to read as follows:

## Appendix E to Part 192—Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

### I. Guidance on Determining a High Consequence Area

To determine which segments of an operator's transmission pipeline system are covered for purposes of the integrity management program requirements, an operator must identify the high consequence areas. An operator must use method (a) or (b) from the definition in § 192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. (Refer to figure E.I.A for a diagram of a high consequence area).

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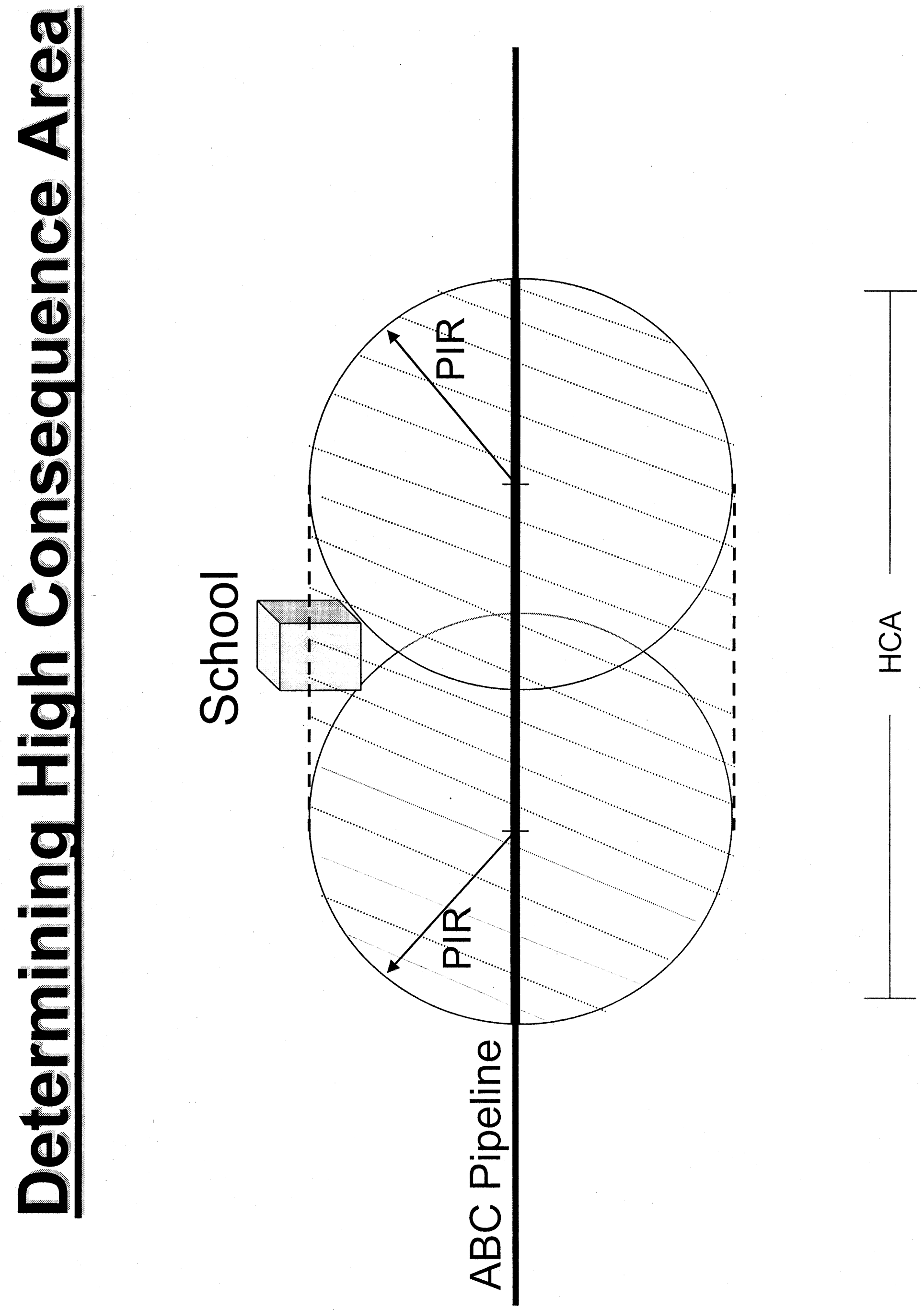


Figure E.I.A

**II. Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines**

(a) Table E.II.1 gives guidance to help an operator implement requirements on additional preventive and mitigative measures for addressing time dependent and independent threats for a transmission pipeline operating below 30% SMYS not in an HCA (*i.e.* outside of potential impact circle) but located within a Class 3 or Class 4 Location.

(b) Table E.II.2 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats for a transmission pipeline in an HCA.

(c) Table E.II.3 gives guidance on preventative & mitigative measures addressing time dependent and independent threats for transmission pipelines that operate below 30% SMYS, in HCAs.

**Table E.II.1: Preventive and Mitigative Measures for Transmission Pipelines Operating Below 30% SMYS not in an HCA but in a Class 3 or Class 4 Location**

| (Column 1) Threat | Existing 192 Requirements | | (Column 4) Additional (to 192 requirements) Preventive and Mitigative Measures |
|---|---|---|---|
| | (Column 2) Primary | (Column 3) Secondary | |
| External Corrosion | 455-(Gen. Post 1971), 457-(Gen. Pre-1971)<br>459-(Examination), 461-(Ext. coating)<br>463-(CP), 465-(Monitoring)<br>467-(Elect isolation), 469-Test stations)<br>471-(Test leads), 473-(Interference)<br>479-(Atmospheric), 481-(Atmospheric)<br>485-(Remedial), 705-(Patrol)<br>706-(Leak survey), 711 (Repair – gen.)<br>717-(Repair – perm.) | 603-(Gen Oper'n)<br>613-(Surveillance) | For Cathodically Protected Transmission Pipeline:<br>• Perform semi-annual leak surveys.<br>For Unprotected Transmission Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impractical:<br>• Perform quarterly leak surveys |
| Internal Corrosion | 475-(Gen IC), 477-(IC monitoring)<br>485-(Remedial), 705-(Patrol)<br>706-(Leak survey), 711 (Repair – gen.)<br>717-(Repair – perm.) | 53(a)-(Materials)<br>603-(Gen Oper'n)<br>613-(Surveillance) | • Perform semi-annual leak surveys. |

| | | | |
|---|---|---|---|
| 3rd Party Damage | 103-(Gen. Design), 111-(Design factor)<br>317-(Hazard prot), 327-(Cover)<br>614-(Dam. Prevent), 616-(Public education)<br>705-(Patrol), 707-(Line markers)<br>711 (Repair – gen.), 717-(Repair – perm.) | 615–(Emerg. Plan) | • Participation in state one-call system,<br><br>• Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND<br><br>• Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred. |

**Table E.II.2 Assessment Requirements for Transmission Pipelines in HCAs (Re-assessment intervals are maximum allowed)**

| | **Re-Assessment Requirements** (see Note 3) | | | | | |
|---|---|---|---|---|---|---|
| | At or above 50% SMYS | | At or above 30% SMYS up to 50% SMYS | | Below 30% SMYS | |
| Baseline Assessment Method (see Note 3) | Max Re-Assessment Interval | Assessment Method | Max Re-Assessment Interval | Assessment Method | Max Re-Assessment Interval | Assessment Method |
| Pressure Testing | 7 | CDA | 7 | CDA | Ongoing | Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2) |
| | 10 | Pressure Test or ILI or DA | | | | |
| | | Repeat inspection cycle every 10 years | 15(see Note 1) | Pressure Test or ILI or DA (see Note 1) | | |
| | | | | Repeat inspection cycle every 15 years | 20 | Pressure Test or ILI or DA |
| | | | | | | Repeat inspection cycle every 20 years |
| In-Line Inspection | 7 | CDA | 7 | CDA | Ongoing | Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2) |
| | 10 | ILI or DA or Pressure Test | | | | |
| | | Repeat inspection cycle every 10 years | 15(see Note 1) | ILI or DA or Pressure Test (see Note 1) | | |
| | | | | Repeat inspection cycle every 15 years | 20 | ILI or DA or Pressure Test |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | Repeat inspection cycle every 20 years |
| Direct Assessment | 7 | CDA | 7 | CDA | Ongoing | Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2) |
| | 10 | DA or ILI or Pressure Test | | | | |
| | | Repeat inspection cycle every 10 years | 15(see Note 1) | DA or ILI or Pressure Test (see Note 1) | | |
| | | | | Repeat inspection cycle every 15 years | 20 | DA or ILI or Pressure Test |
| | | | | | | Repeat inspection cycle every 20 years |

Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S

Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of P&M

Note 3: Operator may utilize "other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe"

**Table E.II.3**

**Preventative & Mitigative Measures addressing Time Dependent and Independent Threats for Transmission Pipelines that Operate Below 30% SMYS , in HCAs**

| Threat | Existing 192 Requirements | | Additional (to 192 requirements) Preventive & Mitigative Measures |
|---|---|---|---|
| | Primary | Secondary | |
| External Corrosion | 455-(Gen. Post 1971)<br>457-(Gen. Pre-1971)<br>459-(Examination)<br>461-(Ext. coating)<br>463-(CP)<br>465-(Monitoring)<br>467-(Elect isolation) | 603-(Gen Oper)<br>613-(Surveil) | For Cathodically Protected Trmn. Pipelines<br>• Perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years. Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment. Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. |

| | | | |
|---|---|---|---|
| External Corrosion | 469-Test stations)<br>471-(Test leads)<br>473-(Interference)<br>479-(Atmospheric)<br>481-(Atmospheric)<br>485-(Remedial)<br>705-(Patrol)<br>706-(Leak survey)<br>711 (Repair – gen.)<br>717-(Repair – perm.) | | For Unprotected Trmn. Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impracticable<br>• Conduct quarterly leak surveys AND<br>• Every 1-1/2 years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. |
| Internal Corrosion | 475-(Gen IC)<br>477-(IC monitoring)<br>485-(Remedial)<br>705-(Patrol)<br>706-(Leak survey)<br>711 (Repair – gen.)<br>717-(Repair – perm.) | 53(a)-(Materials)<br>603-(Gen Oper)<br>613-(Surveil) | • Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCAs,<br>• Periodic testing of fluid removed from pipelines. Specifically, once each calendar year from each storage field that may affect transmission pipelines in HCAs, AND<br>• At least every 7 years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records. |

| | | | |
|---|---|---|---|
| 3rd Party Damage | 103-(Gen. Design)<br>111-(Design factor)<br>317-(Hazard prot)<br>327-(Cover)<br>614-(Dam. Prevent)<br>616-(Public educat)<br>705-(Patrol)<br>707-(Line markers)<br>711 (Repair – gen.)<br>717-(Repair – perm.) | 615 –(Emerg Plan) | • Participation in state one-call system,<br>• Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND<br>• Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred. |

BILLING CODE 4910–60–C

Issued in Washington, DC, on March 17, 2004.

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[FR Doc. 04–6398 Filed 4–5–04; 8:45 am]

BILLING CODE 4910–60–P