REMEDIATION OF DENTS (Continued)			
Pipe Size	**Dent Location**	**Description**	**Schedule**
Equal to or greater than 12"	Any	A dent with a depth[1] greater than 2% of the pipe diameter that affects a girth weld or longitudinal weld seam, with no engineering analysis.	One year
	Any	A dent with a depth[1] greater than 2% of the pipe diameter that affects a girth weld or longitudinal weld seam and engineering analysis demonstrates critical strain levels are not exceeded.	Monitor
	Top 2/3 of pipe	A smooth dent with a depth[1] greater than 6% of the pipe diameter with no engineering analysis.	One year
	Top 2/3 of pipe	A dent with a depth[1] greater than 6% of the pipe diameter and engineering analysis demonstrates critical strain levels are not exceeded.	Monitor
	Bottom 1/3 of pipe	A dent with a depth[1] greater than 6% of the pipe diameter.	Monitor
[1] See 2 of the guide material under §192.309 for measuring the depth of a dent.			

TABLE 192.933ii

3 PRESSURE REDUCTION

(a) Conditions that require a reduction in operating pressure may constitute a safety-related condition. See the guide material under §191.25 where the term "Discovery" is referenced for the purpose of reporting safety-related conditions. This is not necessarily the same as "Discovery of condition" under §192.933. See 1(d) above.
(b) If a pressure reduction exceeds 365 days, the operator is required to provide notification (see §192.949). The notification must include the reasons for not remediating within 365 days, and provide technical justification that the pressure reduction is still adequate.
  (1) Reasons for the delay in remediation could include preventing a service outage or a delay in obtaining any of the following.
    (i) Materials.
    (ii) Permits.
    (iii) Right-of-way.
  (2) Technical justification that the pressure reduction is still adequate should consider one or more of the following.
    (i) Effect of continued corrosion.
    (ii) Environmental changes.
    (iii) Additional pressure cycles.
    (iv) Class location changes.
    (v) Validation of the existing pressure reduction.
(c) If the existing pressure reduction is no longer adequate, the operator should do one of the following.
  (1) Make further reduction in operating pressure.
  (2) Repair or replace the pipe.
  (3) Take pipeline out of service.

§192.935

What additional preventive and mitigative measures must an operator take?

[Effective Date: 03/06/15]

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917.) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(b) *Third party damage and outside force damage*.

(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) Using qualified personnel (see §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(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) Participating in one-call systems in locations where covered segments are present.

(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 SP0502 (incorporated by reference, *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.

(2) *Outside force damage*. If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV)*. If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors — swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(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. 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) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

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

(e) *Plastic transmission pipeline*. An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

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GUIDE MATERIAL

1 ADDITIONAL PREVENTIVE AND MITIGATIVE (P&M) MEASURES (§192.935(a) and (c))

To comply with §192.935, an operator must conduct a risk analysis of all pipelines within HCAs, and determine for each applicable threat on each covered segment whether any of the following (which exceed the requirements of other subparts of Part 192) will prevent pipeline failure or mitigate the consequences of such a failure.

Some activities performed as requirements for additional preventative and mitigative measures may also be used to satisfy similar program requirements under §§192.614, 192.615, 192.616, and 192.620(d)(2).

(a) Installation of an automatic shut-off valve (ASV) or a remote control valve (RCV).

(1) To comply with §192.935(c), an operator must consider the following factors in determining if an ASV or RCV would be an efficient means of adding protection in an HCA.

(i) Swiftness of leak detection. Example: There may be no advantage to installing an ASV or RCV on segments where adequate SCADA or other monitoring methods allow for quick operator response to leakage.

(ii) Shutdown capabilities in the area. Example: An ASV or RCV might not make shutdown any faster or easier in locations where adequate valving and easy access already exists.

(iii) Type of gas. Example: An ASV or RCV might mitigate the environmental impact of leakage on a pipeline carrying heavier-than-air gases.

(iv) Operating pressure. Example: Higher-pressure lines hold a larger volume of gas. An ASV or RCV on such a line may reduce the volume of release and potential for ignition.

(v) Potential release rate. Example: Installing an ASV or RCV may affect the duration of the potential release rate.

(vi) Pipeline profile. Example: Heavier-than-air gases can pool in low elevation spots. An ASV or RCV in such locations may allow faster shut off and, therefore, less accumulation of gas.

(vii) Potential for ignition. Example: Areas that have known sources of ignition (e.g., foundries) might benefit from an ASV or RCV.

(viii) Location of nearest response personnel. Example: Locations where operator response is timely may not benefit from the installation of an ASV or RCV.

(2) An operator may also consider the following.
    (i) Seasonal weather restrictions that can impede access.
    (ii) Depth of pipe as it relates to access for squeeze-off.
    (iii) River crossings or other geographical features that affect access for maintenance or response.
    (iv) Proximity of the HCA to existing valves.
    (v) Population density.
    (vi) Wide pressure fluctuations due to normal operating conditions (e.g., power plant locations).
    (vii) Maintenance, reliability, and cost-benefit issues.

(b) Installation of computerized monitoring and leak detection systems.
An operator may consider the following, which could provide earlier leak or pipeline rupture detection.
(1) Increasing the locations monitored by SCADA.
(2) Automating data gathering from other monitoring devices such as pressure transmitters.

(c) Replacing pipe with that of heavier-wall thickness, which is more resistant to damage from external forces.

(d) Providing additional training on response procedures.
An operator may consider the following.
(1) Increasing the frequency of emergency response training.
(2) Conducting tabletop or field drills.
(3) Hiring a third party with expertise in emergency response to conduct training.
(4) Attending emergency response training offered by industry associations.

(e) Conducting drills with local emergency responders.
The operator may consider the following.
(1) Including the drill as part of liaison meetings with emergency responders.
(2) Working with local multi-agency, emergency coordination groups.
(3) Incorporating the drill into local fire or police academy curriculum.

(f) Implementing additional inspection and maintenance programs.
The operator may consider the following.
(1) Increasing leak survey frequencies.
(2) Increasing patrol frequencies.
(3) Using procedures with more stringent criteria than required by the Regulations.
(4) Increasing facility inspection frequencies.

2 THIRD-PARTY DAMAGE (§192.935(b)(1))

To comply with §192.935(b)(1) for the specific threat of third-party damage, an operator must do the following.

(a) Qualify personnel to conduct the following activities related to work the operator is conducting in a covered segment.
(1) Locating the pipeline.
(2) Marking the pipeline.
(3) Directly supervising known excavation work. A qualification for this activity might include the following.
    (i) Recognition of line-locate markings.
    (ii) Knowledge of one-call requirements.
    (iii) Knowledge of operator's applicable procedures, including emergency response.
    (iv) Understanding the risks of various excavation methods.
(4) Other activities that could adversely affect the integrity of the pipeline.

(b) Use a central database to collect the following.
  (1) Excavation damage information for covered and non-covered segments. This might include the following.
    (i) Number of leaks or ruptures.
    (ii) Number of known damages not resulting in leaks or ruptures.
    (iii) Excavation method.
    (iv) Name of excavator causing damage.
  (2) Root-cause analysis data to identify targeted P&M measures for HCAs. This might include the number of damages where:
    (i) No line locate was requested.
    (ii) Line was incorrectly marked.
    (iii) Line was not marked.
    (iv) Construction procedures were not followed correctly (e.g., exposing lines during boring).
  (3) Damage data that is not DOT reportable (reference Part 191 requirements). This might include known items such as the following.
    (i) Dents.
    (ii) Gouges.
    (iii) Coating damage.
    (iv) Damage to pipeline supports or river anchors.
(c) Participate in a one-call program wherever there are covered segments.
(d) Monitor excavations on covered segments. An operator may want to consider the following.
  (1) Mapping HCAs so field personnel can easily recognize when they are in an area that requires monitoring.
  (2) Creating a business process that alerts the appropriate departments of pending excavations.
  (3) Working with the local One-Call Center to notify excavators and operators when monitoring is required.
  (4) Training line locators to notify appropriate personnel when they know work will take place in an HCA.
  (5) Documenting excavation monitoring using one or more of the following.
    (i) Time card accounting.
    (ii) Special forms.
    (iii) Time-stamped electronic data.
    (iv) Maps.
(e) When there is physical evidence of an excavation near a covered segment that the operator did not monitor, either excavate the area or conduct an aboveground survey (e.g., DCVG) as defined in NACE SP0502-2008 (see §192.7 for IBR). Examples of how to identify an encroachment might include the following.
  (1) New pavement patches.
  (2) Heavy equipment on site.
  (3) Disturbed earth.
  (4) New structures requiring excavation (e.g., fence posts, telephone poles, buildings, slabs).
  (5) Exposed pipe.
  (6) New landscaping.
  (7) One-call documentation.

3 OUTSIDE FORCE DAMAGE (§192.935(b)(2))

To comply with §192.935(b)(2) for the specific threat of outside force damage (e.g., earth movement, floods, unstable suspension bridge), an operator must take additional measures to minimize the consequences of outside force.

(a) The measures include the following.
  (1) Increasing the frequency of patrols. This may allow faster recognition of damage.
  (2) Adding external protection. This might include the following.
    (i) Installing fencing or other barriers to impede earth movement.
    (ii) External slabs or additional cover.
  (3) Reducing external stress. This might include the following.

- (i) Installing expansion joints.
- (ii) Removing overburden.

(4) Relocating the pipeline to an area with less exposure to outside forces. This might include lowering or raising the pipeline.

(b) An operator may also consider installing the following.
- (1) River anchors where appropriate.
- (2) Elevated relief or vent stacks on regulator stations.
- (3) Additional bridge hangers or pipe supports.

4 PIPELINES OPERATING BELOW 30 PERCENT SMYS (§192.935(d))

Pipelines operating below 30% SMYS have additional requirements as addressed below. For guidance related to these additional requirements, see Appendix E to Part 192.

(a) For all Class locations in an HCA, the following apply.
- (1) Qualify personnel to conduct the following activities related to work the operator is conducting in a covered segment.
  - (i) Locating the pipeline.
  - (ii) Marking the pipeline.
  - (iii) Directly supervising known excavation work. A qualification for this activity might include the following.
    - (A) Recognition of line-locate markings.
    - (B) Knowledge of one-call requirements.
    - (C) Knowledge of operator's applicable procedures, including emergency response.
    - (D) Understanding the risks of various excavation methods.
  - (iv) Other activities that could adversely affect the integrity of the pipeline.
- (2) Participate in a one-call program wherever there are covered segments.
- (3) Either monitor excavations near the pipeline, or conduct patrols on a bi-monthly frequency. Any indication of unreported construction activity requires an investigation to determine if any damage has occurred.

(b) For Class 3 or Class 4 locations outside of an HCA.
- (1) Qualify personnel to conduct the following activities related to work the operator is conducting in covered segment.
  - (i) Locating the pipeline.
  - (ii) Marking the pipeline.
  - (iii) Directly supervising known excavation work. A qualification for this activity might include the following.
    - (A) Recognition of line-locate markings.
    - (B) Knowledge of one-call requirements.
    - (C) Knowledge of operator's applicable procedures, including emergency response.
    - (D) Understanding the risks of various excavation methods.
  - (iv) Other activities that could adversely affect the integrity of the pipeline.
- (2) Participate in a one-call program wherever there are covered segments.
- (3) Either monitor excavations near the pipeline, or conduct patrols on a bi-monthly frequency. Any indication of unreported construction activity requires an investigation to determine if any damage has occurred.
- (4) Perform semi-annual leak surveys. For unprotected or cathodically protected pipe where electrical surveys are impractical, perform quarterly leak surveys.

(c) See Table 192.935i.

5 PLASTIC TRANSMISSION LINES (§192.935(e))

Plastic transmission lines have additional requirements as follows.

(a) Qualify personnel to conduct the following activities related to work the operator is conducting in a covered segment.
  (1) Locating the pipeline.
  (2) Marking the pipeline.
  (3) Directly supervising known excavation work. A qualification for this activity might include the following.
    (i) Recognition of line-locate markings.
    (ii) Knowledge of one-call requirements.
    (iii) Knowledge of operator's applicable procedures, including emergency response.
    (iv) Understanding the risks of various excavation methods.
  (4) Other activities that could adversely affect the integrity of the pipeline.

(b) Participate in a one-call program wherever there are covered segments.

(c) Monitor excavations on covered segments. An operator may want to consider the following.
  (1) Mapping HCAs so field personnel can easily recognize when they are in an area that requires monitoring.
  (2) Creating a business process that alerts the appropriate departments of pending excavations.
  (3) Working with the local One-Call Center to notify excavators and operators when monitoring is required.
  (4) Training line locators to notify appropriate personnel when they know work will take place in an HCA.
  (5) Documenting excavation monitoring by using one or more of the following.
    (i) Time card accounting.
    (ii) Special forms.
    (iii) Time-stamped electronic data.
    (iv) Maps.

(d) When there is physical evidence of an encroachment on a covered segment that the operator did not monitor, excavate the area to determine if any damage has occurred. Examples of how to identify an encroachment include the following.
  (1) New pavement patches.
  (2) Heavy equipment on site.
  (3) Disturbed earth.
  (4) New structures requiring excavation (e.g., fence posts, telephone poles, buildings, slabs).
  (5) Exposed pipe.
  (6) New landscaping.
  (7) One-call documentation.

(e) See Table 192.935i.

ADDITIONAL P&M MEASURES FOR TRANSMISSION PIPELINES OPERATING BELOW 30 PERCENT SMYS AND PLASTIC TRANSMISSION LINES

Location	General Requirements	Use Qualified Personnel	Participate in one-call	Monitor Excavations or Additional Patrol	Additional Leak Survey
Class 1 & 2 in HCA	X	X	X	X	
Class 1 & 2 outside HCA					
Class 3 & 4 in HCA	X	X	X	X	
Class 3 & 4 outside HCA		X	X	X	X
Plastic Transmission	X	X	X	X (monitor only) [1]	

[1] The option of patrolling is not available for plastic transmission lines.

TABLE 192.935i

§192.937

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

[Effective Date: 07/10/06]

(a) *General*. After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation*. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods*. In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (see §192.917), or by confirmatory direct assessment under the conditions specified in §192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(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) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(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.

(5) 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 §192.931.

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GUIDE MATERIAL

1 GENERAL

See the guide material under §192.939 for reassessment intervals.

2 EVALUATION FOR COVERED SEGMENTS

One of the goals of periodic evaluation is to determine what is changing and what actions are needed to maintain safe operations. Periodic evaluations are based on integrating information, identifying changes to pipeline threats, and updating risk analyses. This evaluation is intended to support the identification of changes needed to assessment frequencies, assessment types, and preventive and mitigative (P&M) measures.

2.1 Frequency.

When determining the frequency, the operator should consider the following.

(a) The number and types of changes that are occurring. For example, if there are no changes to HCAs, MAOPs, or personnel, a longer interval may be appropriate.
(b) For pipe subject to low stress reassessment, the requirement to evaluate external corrosion data for:
  (1) Cathodically protected lines at least once every 7 years (§192.941(b)(1)), or
  (2) Unprotected pipe at least once every 18 months (§192.941(b)(2)).
(c) For pipe subject to low stress reassessment, the requirement to evaluate internal corrosion data at least once every 7 years (§192.941(c)(3)).
(d) The evaluation intervals should not exceed the assessment intervals listed in ASME B31.8S-2004, Section 5, Table 3 (see §192.7 for IBR).
(e) Items that might trigger an evaluation (e.g., incidents, new data) before the scheduled evaluation.

2.2 Data integration.

Use information collected through assessment, remediation, and P&M measures to update records where default values were used, or that have been determined to be inaccurate or incomplete.

2.3 Threat identification.

Use information collected through assessment, remediation, and P&M measures to identify new threats or to evaluate the severity of existing threats. Additional changes to threats may be identified through the evaluation of the following.

(a) Failures.
(b) Incidents.
(c) Abnormal operations.
(d) Lessons learned.
(e) Performance metrics.

2.4 Risk analysis.

(a) Use information collected through assessment, remediation, and P&M measures to determine if the risk ranking is consistent with the results.
(b) Use information collected through data integration, assessment, remediation, and P&M measures to update the risk model.
(c) Changes to segments included in risk assessment may be identified through the evaluation of the following.
  (1) System modifications.
  (2) HCA changes.
  (3) O&M activities.
  (4) Operational changes.
  (5) Environmental changes.

2.5 Subsequent actions driven by periodic evaluation.

(a) Identify changes required to assessment intervals.
(b) Confirm that assessment methods are applicable for the identified threats.
(c) If current methods are not effective for current threats, determine correct assessment methods and reassess applicable segments.
(d) Determine the effectiveness of current P&M measures.
(e) Determine the need for changes to existing P&M measures or implementation of additional measures.
(f) If an operator changes the criteria for grading ILI anomalies, the operator should review the impact of the changes on anomalies discovered during the prior assessments.
(g) If an operator changes ECDA or ICDA criteria for classifying indications, or for calculating the remaining life, the operator should review the impact of the changes on the results from the prior assessment.
(h) Evaluate the potential requirement for assessment and remediation of a threat on other pipeline segments as follows.
  (1) Similar pipeline segments when corrosion or seam issues are identified as a threat in a covered segment.
  (2) Similar covered segments when any threats are identified outside a covered segment.

3 ASSESSMENT METHODS

(a) For reassessment methods, see the guide material under §192.921.
(b) For CDA, see guide material under §192.931.

§192.939

What are the required reassessment intervals?

[Effective Date: 03/06/15]

An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

(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) *Pressure test or internal inspection or other equivalent technology*. An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by —

(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

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, *see* §192.7), section 5, Table 3.

(2) *External Corrosion Direct Assessment*. An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, *see* §192.7).

(3) *Internal Corrosion or SCC Direct Assessment*. An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

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

(ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and

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

(b) *Pipelines Operating Below 30% SMYS*. An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following —

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941.

(2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

(3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.

(4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with §192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this