Gas Integrity Management Protocols

Explanation of Protocol Format

Each protocol element will have top-tier protocols that address the high level requirements. The regulatory requirement upon which the protocol is based is contained in brackets.

Each top-tier protocol will have detailed "sub-tier" protocols which collectively lead the inspector to draw overall conclusions about compliance with the top-tier protocol. The regulatory requirement, upon which each sub-tier protocol is based, is also contained in brackets.

Notes on protocols:

- The typical sentence structure used in the protocols follows the form of "Verify that [describe the requirement]." The use and meaning of the term "verify" is expanded upon below.

- OPS will "verify" an operator's compliance status with respect to each requirement. In order to perform this verification, OPS will inspect the operator's documented processes and procedures in order to determine if a program has been established that complies with rule requirements. In addition, OPS will inspect an operator's implementation records to determine if the operator is effectively implementing its programs and processes. The purpose of the OPS verification/inspection is not to perform a quality check of every integrity related activity. The OPS inspection is conducted in the form of an audit. As a result, the OPS inspection will typically perform an inspection of selected operator records sufficient in breadth and depth to give the inspection team adequate understanding regarding the degree of an operator's commitment to compliance with applicable requirements and/or the degree to which the operator's program has been effective with respect to achieving compliance. OPS may use any number of inspection or audit techniques to identify potential compliance issues. Program documents may be inspected to determine if adequate processes have been developed and documented to the degree necessary for competent professionals to understand and effectively implement the process with results that are consistent and repeatable. For example, one technique that might be used by the inspection team is a "vertical slice" in which a specific covered segment or pipeline system is selected to perform a detailed inspection of every aspect of integrity management, thus following a specific example through the entire process of integrity management. Based on those reviews, OPS will identify potential non-compliances with rule requirements. OPS can not and will not certify nor conclude that an operator is in full compliance with rule requirements, even if the inspection does not identify any areas of non-compliance. Operators are wholly responsible for compliance with regulations.

- References to regulatory requirements may include references to specific rule sections/paragraphs and/or to industry standards that are invoked in the rule. As specified in §192.7, any requirement invoked by reference is a requirement of the rule as though it were set out in full in the regulation.

- Protocols are designated with either [P] or [I] or both [PI]. These indicate that the inspection will focus on the process [P] and operator has developed in its program plans and/or procedures, or that the inspection will focus on implementation [I] records that demonstrate the operator has effectively implemented the process its has developed or is implementing rule requirements. Most protocols will be designated as both [PI].

- Protocols are subject to change without notice.

- Protocols are an initial guide for use by OPS inspectors during Integrity Management inspections. Inspectors will develop additional questioning during the course of the inspection to investigate the specifics of an operator's program. Protocols are not to be construed as an exhaustive list of questions that may be presented to operators during an inspection.

- Protocols are made publicly available as a courtesy to operators as they develop their Integrity Management program, as well as other stakeholders.

A. Identify HCAs

A.1 Program Requirements Verify that the methods defined in §192.903 High Consequence Area (1) and/or §192.903 High Consequence Area (2) are applied to each pipeline for the identification of high consequence areas. [§192.905(a)]

a. **[P]** Verify the operator's integrity management program includes documented processes on how to implement methods (1) and (2) in order to identify high consequence areas. [§192.905(a)]

b. **[PI]** Verify that the operator's process requires that the method used for each portion of the pipeline system be documented. [§192.905(a)]

c. **[PI]** Verify that the operator's integrity management program includes system maps or other suitably detailed means documenting the pipeline segment locations that are located in high consequence areas. [§192.905(a)]

d. **[PI]** Review HCA records to verify that the operator completed identification of pipeline segments in high consequence areas by December 17, 2004. [§192.907, §192.911(a)]

A.2 Potential Impact Radius Verify that the definition and use of potential impact radius for establishment of high consequence areas meets the requirements of §192.903. [§192.905(a)]

a. **[P]** Verify that the operator's formula for calculation of the potential impact radius is consistent with §192.903 requirements ($r = 0.69*(p*d^2)^{0.5}$) and that the pressure used in the formula is based on maximum allowable operating pressure (MAOP).

i. For gases other than natural gas, verify that the operator has documented processes for the use of Section 3.2 of ASME/ANSI B31.8S to calculate the impact radius formula. [§192.903 Potential Impact Radius, §192.905(a)]

b. **[PI]** In cases where potential impact circles are used to identify high consequence areas, verify that the program requires that high consequence areas include the area extending axially along the length of the pipeline from the outermost edge of the first potential impact circle to the outermost edge of the last contiguous potential impact circle for those potential impact circles that contain either an identified site or 20 or more buildings intended for human occupancy. [§192.903 High Consequence Area (3)]

A.3 Identified Sites Verify that the operator's identification of identified sites includes the sources listed in §192.905(b) for those buildings or outside areas meeting the criteria specified by §192.903, and that the source of information selected is documented. [§192.903 Identified Sites, §192.905(b) and §192 Appendix E, I(c)]

a. **[PI]** Identified sites must include the following: [§192.903 Identified Sites, §192.905(b)]

i. Outside areas or open structures occupied by 20 or more people on at least 50 days in any 12 month period (days need not be consecutive),

ii. Buildings occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12 month period (days and weeks need not be consecutive), and
iii. Facilities occupied by persons who are confined, have impaired mobility, or would be difficult to evacuate.

b. **[PI]** Identified sites must be identified using the following sources of information: [§192.905(b)]

i. Information from routine operation and maintenance activities and input from public officials with safety or emergency response or planning responsibilities
ii. In the absence of public official input, the operator must use one of the following in order to identify an identified site:
   1. Visible markings such as signs, or
   2. Facility licensing or registration data on file with Federal, State, or local government agencies, or
   3. Lists or maps maintained by or available from a Federal, State, or local government agency and available to the general public.

A.4 Identification Using Class Locations (Method 1) If the operator's integrity management program relies on §192.903 High Consequence Area definition (1) for identification of high consequence areas, verify compliance with the following:

a. **[PI]** Verify the integrity management program includes Class 3 and Class 4 piping locations as high consequence areas consistent with the criteria of §192.5(b)(3) and §192.5(b)(4), and §192.5(c). [§192.903 High Consequence Area (1)(i) and (ii)]

b. **[PI]** For Class 1 and Class 2 locations with the potential impact radius greater than 660 feet, verify the integrity management program includes piping locations as high consequence areas if the area within the associated potential impact circle contains 20 or more buildings intended for human occupancy.[§192.903 High Consequence Area (1)(iii)]

i. As an option for PIRs greater than 660 feet, the definition of high consequence area may be based on a prorated building count for buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline as calculated using the following formula: [§192.903 High Consequence Area (4)]

$$\text{Building Count within 660 feet} = 20 \times [660\ (\text{ft}) / \text{PIR}\ (\text{ft})]^2 \text{ or}$$
$$\text{Building Count within 200 meters} = 20 \times [200\ (\text{m}) / \text{PIR}\ (\text{m})]^2$$

   1. If the option for use of a prorated number of buildings has been used for identification of high consequence areas, verify that the program acknowledges that use of the prorated allowance is only available to operators until December 17, 2006. [§192.903 High Consequence Area (4)]

c. **[PI]** Verify the program includes as a high consequence area, any area in Class 1 and Class 2 piping locations where the potential impact circle contains an identified site. [§192.903 High Consequence Area (1)(iv)]

A.5 Identification Using Potential Impact Radius (Method 2) If the operator's integrity management program relies on §192.903 High Consequence Area definition (2) for identification of high consequence areas, verify compliance with the following:

a. **[PI]** Verify the integrity management program includes piping locations as high consequence areas if the area within a potential impact circle contains 20 or more buildings intended for human occupancy: [§192.903 High Consequence Area (2)(i)]

i. As an option for PIRs greater than 660 feet, the definition of high consequence area may be based on a prorated building count for buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline as calculated using the following formula: [§192.903 High Consequence Area (4)]

Building Count within 660 feet = 20 x $[660\ (\text{ft}) / \text{PIR}\ (\text{ft})]^2$ or
Building Count within 200 meters = 20 x $[200\ (\text{m}) / \text{PIR}\ (\text{m})]^2$

1. If the option for use of a prorated number of buildings has been used for identification of high consequence areas, verify that the program acknowledges that use of the prorated allowance is only available to operators until December 17, 2006. [§192.903 High Consequence Area (4)]

b. **[PI]** Verify the program includes piping locations as high consequence areas if the area within the potential impact circle contains an identified site. [§192.903 High Consequence Area (2)(ii)]

A.6 Identification and Assessment of Newly Identified HCAs, Program Requirements Review the operator's integrity management program to verify processes are in place for evaluation of new information that may show that a pipeline segment impacts a high consequence area. [§192.905(c)]

a. **[P]** Verify the operator's integrity management program includes documented processes for how new information that shows a pipeline segment impacts a high consequence area is identified and integrated with the integrity management program. The program is to identify and analyze changes for impacts on pipeline segments potentially affecting high consequence areas. Issues the program must consider include but are not limited to:[§192.905(c)]

i. Changes in pipeline maximum allowable operating pressure (MAOP),
ii. Pipeline modifications affecting piping diameter,
iii. Changes in the commodity transported in the pipeline,

iv. Identification of new construction in the vicinity of the pipeline that results in additional buildings intended for human occupancy or additional identified sites,
v. Change in the use of existing buildings (e.g., hotel or house converted to nursing home),
vi. Installation of new pipeline,
vii. Change in pipeline class location (e.g., class 2 to 3) or class location boundary,
viii. Pipeline reroutes
ix. Corrections to erroneous pipeline center line data,
x. Field design changes (addition of taps, maintenance, pressure settings, etc.) affecting line pressure, diameter, or pipeline location.

B. Baseline Assessment Plan

B.1 Assessment Methods Verify that the operator's Baseline Assessment Plan (BAP) specifies an assessment method(s) for each covered segment that is best suited for identifying anomalies associated with specific threats identified for the segment. Verify that the operator followed ASME/ANSI B31.8S, Section 6 and that the methods selected address all of the threats identified to the covered segments. More than one assessment tool may be necessary to address all applicable threats. [§192.919(b), 192.921(a), 192.921(c), 192.921(h)]

a. **[PI]** If internal inspection tools are selected, verify that the operator followed ASME/ANSI B31.8S, Section 6.2 in selecting the appropriate internal inspection tool for the covered segment. [§192.921(a)(1)]

i. Verify that the operator has evaluated the general reliability of any in-line assessment method selected by looking at factors including but not limited to: detection sensitivity; anomaly classification; sizing accuracy; location accuracy; requirements for direct examination; history of tool; ability to inspect full length and full circumference of the section; and ability to indicate the presence of multiple cause anomalies. Refer to ASME/ANSI B31.8S, section 6.2.5. [§192.921(a)(1)]

b. **[PI]** If a pressure test is specified, verify that the test is required to be conducted in accordance with Part 192, Subpart J requirements. Verify that the operator followed ASME/ANSI B31.8S, Section 6.3 in selecting the pressure test as the appropriate assessment method. [§192.921(a)(2)]

c. **[PI]** If the operator specifies the use of "other technology," verify that notification to OPS is required in accordance with Part 192.949, 180 days before conducting the assessment. Also, verify that notification to a State or local pipeline safety authority is required 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. [§192.921(a)(4)]

d. **[PI]** If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW) or lap welded pipe that satisfies the conditions specified in ASME/ANSI B31.8 S, Appendix A4.3 and A4.4, and any covered or non-covered 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 verify that the selected assessment method(s) are proven to be capable of assessing seam integrity and detecting seam corrosion anomalies. [§192.917(e)(4)]

e. **[PI]** If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, verify that the operator documents an acceptable justification for the use of an alternative assessment method that will address the identified threats to the covered segment. [§192.921(h)]

B.2 Prioritized Schedule Verify that the BAP contains a schedule for completing the assessment activities for all covered segments; and that the BAP appropriately considered the applicable risk factors in the prioritization of the schedule. [§192.917(c), 192.919(c), 192.921]

a. **[PI]** Verify that the BAP schedule includes all covered segments not already assessed. [§192.921(a)]

b. **[PI]** Verify that the BAP schedule prioritizes the covered segments based on potential threats and applicable risk analysis, and that the risk ranking is appropriate. [§192.917(c), 192.921(b)]

c. **[PI]** Verify that covered segments meeting the following conditions are prioritized as high-risk segments.

i. Segments that contain low frequency resistance welded (ERW) pipe or lap welded pipe that satisfy the conditions specified in ASME/ANSI B31.8S, Appendix A4.3 and A4.4, and any covered or non-covered 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. [§192.917(e)(4)]

ii. Covered segments that have manufacturing or construction defects (including seam defects) where any of the following changes occurred in the covered segment: operating pressure increases above the maximum operating pressure experienced during the preceding five years; MAOP increases; or the stresses leading to cyclic fatigue increase. [§192.917(e)(3)]

d. **[PI]** Verify that the BAP schedule requires 50% of the covered segments, beginning with the highest risk segments, to be assessed by December 17, 2007; and that baseline assessments shall be completed for all covered segments by December 17, 2012. [§192.921(d)]

e. **[I]** Review the operator's implementation progress to date and verify that: [§192.921]

i. Assessments scheduled for completion by the date of the inspection were in fact completed.

ii. Assessment methods used for completed assessments were as described in the plan.

iii. The date assessment field activities were completed is recorded [so the operator understands the time frame allowable for compliance with the provisions of 192.933].

B.3 Use of Prior Assessments If prior assessments are used in the BAP, verify that the assessment methods used meet the requirements of 192.921(a) and that remedial actions have been carried out to address conditions listed in section 192.933. Prior assessments are those that were completed prior to December 17, 2002. [§192.921(e)]

a. **[PI]** Verify that threats to these pipeline sections were identified as required under 192.919(a).

b. **[PI]** Verify that the methods used for these prior assessments were appropriate for the threats per ANSI B31.8S as required under 192.919(b) and 192.919(d).

c. **[PI]** Verify that anomalies satisfying the requirements of 192.933 were repaired.

B.4 Newly Identified HCAs/Newly Installed Pipe Verify that the operator updates the baseline assessment plan for newly identified HCAs and newly installed pipe. [§192.905(c), 192.921(f), 192.921(g)]

a. **[PI]** If new HCAs have been identified or new pipe has been installed that is covered by this subpart, verify that applicable segment(s) have been incorporated into the operator's baseline assessment plan within one year from the date the area or pipe is identified and assessments have been appropriately scheduled and/or completed. [§192.905(c)]

b. **[PI]** For newly identified HCAs, verify that the operator completes a baseline assessment for the applicable segment(s) within ten (10) years from the date the area is identified. [§192.921(f)]

c. **[PI]** For newly installed pipe that is covered by this subpart and impacts an HCA, verify that the operator completes a baseline assessment within ten (10) years from the date the pipe is installed. [§192.921(g)]

d. **[PI]** Verify that threats to these pipeline sections were identified as required under 192.919(a). [§192.921(b)]

e. **[PI]** Verify that the assessment methods used were appropriate for the threats per ASME/ANSI B31.8S as required under 192.919(b) and 192.919(d).

B.5 Consideration of Environmental and Safety Risks Verify that the operator addresses requirements for conducting the baseline assessments in a manner that minimizes environmental and safety risks. [§192.919(e)]

a. **[PI]** Verify that precautions were implemented to protect workers, members of the public, and the environment from safety hazards (such as an accidental release of gas) during assessments. [§192.919(e)]

B.6 Changes Verify that the operator keeps the BAP up-to-date with respect to newly arising information. Also refer to Protocol K. [§192.911(k) & ASME/ANSI B31.8S, Section 11]

a. **[P]** Verify that the operator's process has requirements to keep the BAP up-to-date with respect to newly arising information, applicable threats, and risks that may require changes to the segment prioritization or assessment method. [§192.911(k) & ASME/ANSI B31.8S, Section 11]

b. **[I]** Verify that required BAP changes have been made and that for all changes, the following are documented: [ASME/ANSI B31.8S, Section 11(a)]

i. Reason for change

ii. Authority for approving change
iii. Analysis of implications
iv. Communication of change to affected parties

C. Identify Threats, Data Integration, and Risk Assessment

C.1 Threat Identification Verify that the operator identifies and evaluates all potential threats to each covered pipeline segment. [§192.917(a)]

a. **[PI]** If the operator is following the prescriptive or performance-related approaches, verify that the following categories of failure have been considered and evaluated: [§192.917(a) & ASME/ANSI B31.8S, Section 2.2]

i. external corrosion,
ii. internal corrosion,
iii. stress corrosion cracking;
iv. manufacturing-related defects, including the use of low frequency electric resistance welded (ERW) pipe, lap welded pipe, flash welded pipe, or other pipe potentially susceptible to manufacturing defects [§192.917(e)(4), ASME/ANSI B31.8S Appendix A4.3];
v. welding- or fabrication-related defects,
vi. equipment failures;
vii. third party/mechanical damage [§192.917(e)(1)],
viii. incorrect operations (including human error),
ix. weather-related and outside force damage,
x. cyclic fatigue or other loading condition [§192.917(e)(2)],
xi. all other potential threats.

b. **[PI]** If the operator is following the performance-based approach, verify that all 21 of the threats associated with the first nine failure categories listed above have been considered. [§192.917(a) & ASME/ANSI B31.8S, Section 2.2]

c. **[PI]** Verify that the operator's threat identification has considered interactive threats from different categories (e.g., manufacturing defects activated by pressure cycling, corrosion accelerated by third party or outside force damage) [ASME/ANSI B31.8S, Section 2.2].

d. **[PI]** Verify that the approach incorporates appropriate criteria for eliminating from consideration a specific threat for a particular pipeline segment. [ASME B31.8S, §5.10]

C.2 Data Gathering and Integration Verify that the operator gathers and integrates existing data and information on the entire pipeline that could be relevant to covered segments, and verify that the necessary pipeline data have been assembled and integrated. [§192.917(b)]

a. **[PI]** Verify that the operator has in place a comprehensive plan for collecting, reviewing, and analyzing the data. [ASME B31.8S, 4.2. & 4.4]

b. **[PI]** Verify that the operator has assembled data sets for threat identification and risk assessment according to the requirements in ASME/ANSI B31.8S, sections 4.2, 4.3, and 4.4. At a minimum, an operator must:

i. gather and evaluate the set of data specified in ASME/ANSI B31.8S, Appendix A (summarized in ASME/ANSI B31.8S, Table 1); and
ii. consider the following on covered segments and similar non-covered segments [§192.917(b)]:
   1. Past incident history
   2. Corrosion control records
   3. Continuing surveillance records
   4. Patrolling records
   5. Maintenance history
   6. Internal inspection records
   7. All other conditions specific to each pipeline.

c. **[PI]** Verify that the operator has utilized the data sources listed in ASME B31.8S, Table 2, for initiation of the integrity management program. [ASME B31.8S, §4.3]

d. **[PI]** Verify that the operator has checked the data for accuracy. If the operator lacks sufficient data or where data quality is suspect, verify that the operator has followed the requirements in ASME/ANS B31.8S, section 4.2.1, section 4.4, and Appendix A [ASME B31.8S, 4.1, 4.2.1, 4.4, 5.7(e), and Appendix A]:

i. Each threat covered by the missing or suspect data is assumed to apply to the segment being evaluated. The unavailability of identified data elements is not a justification for exclusion of a threat.
ii. Conservative assumptions are used in the risk assessment for that threat and segment or the segment is given higher priority.
iii. Records are maintained that identify how unsubstantiated data are used, so that the impact on the variability and accuracy of assessment results can be considered.
iv. Depending on the importance of the data, additional inspection actions or field data collection efforts may be required.

e. **[PI]** Verify that the operator's program includes measures to ensure that new information is incorporated in a timely and effective manner, as addressed in Protocol K. [§192.911(k) & ASME B31.8S, §§11(b) & 11(d)]

f. **[PI]** Verify that individual data elements are brought together and analyzed in their context such that the integrated data can provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk. [ASME B31.8S, §4.5]. Data integration includes:

i. A common spatial reference system that allows association of data elements with accurate locations on the pipeline [ASME B31.8S, §4.5];
ii. Integration of ILI or ECDA results with data on encroachments or foreign line crossings in the same segment to define locations of potential third party damage [§192.917(e)(1)].

C.3 Risk Assessment Verify that the operator has conducted a risk assessment that follows ASME/ANSI B31.8S, section 5, and that considers the identified threats for each covered segment. [§192.917(c)][Note: Application of the risk assessment to prioritize the covered segments for the baseline assessment is covered in Protocol Area B, continual reassessments in Protocol Area F, and additional preventive and mitigative measures in Protocol Area H.]

a. **[PI]** Verify that the operator's risk assessment supports the following objectives [ASME B31.8S, §5.3, 5.4]:

i. prioritization of pipelines/segments for scheduling integrity assessments and mitigating action
ii. assessment of the benefits derived from mitigating action
iii. determination of the most effective mitigation measures for the identified threats
iv. assessment of the integrity impact from modified inspection intervals
v. assessment of the use of or need for alternative inspection methodologies
vi. more effective resource allocation
vii. facilitation of decisions to address risks along a pipeline or within a facility

b. **[PI]** Verify that the operator utilizes one or more of the following risk assessment approaches [ASME B31.8S, §5.5]:

i. Subject matter experts (SMEs),
ii. Relative assessment models,
iii. Scenario-based models, or
iv. Probabilistic models

c. **[PI]** Verify that the risk assessment explicitly accounts for factors that could affect the likelihood of a release and for factors that could affect the consequences of potential releases, and that these factors are combined in an appropriate manner to produce a risk value for each pipeline segment. [ASME B31.8S, 3.1, 3.3, 5.2,§5.3, 5.7(j)] Verify that the risk assessment approach includes the following characteristics:

i. The risk assessment approach contains a defined logic and is structured to provide a complete, accurate, and objective analysis of risk [ASME B31.8S, section 5.7(a)];
ii. The risk assessment considers the frequency and consequences of past events, using company and industry data [ASME B31.8S, section 5.7(c)];
iii. The risk assessment approach integrates the results of pipeline inspections in the development of risk estimates [ASME B31.8S, section 5.7(d)];
iv. The risk assessment process includes a structured set of weighting factors to indicate the relative level of influence of each risk assessment component [ASME B31.8S, section 5.7(i)];
v. The risk assessment process incorporates sufficient resolution of pipeline segment size to analyze data as it exists along the pipeline [ASME B31.8S, section 5.7(k)];

d. **[PI]** Verify that the operator's process provides for revisions to the risk assessment if new information is obtained or conditions change on the pipeline segments. Verify that the provisions for change to the risk assessment address the following areas:

i. the risk assessment plan calls for recalculating the risk for each segment to reflect the results from an integrity assessment or to account for completed prevention and mitigation actions. [ASME B31.8S, §5.11, 5.7(c)]
ii. the operator integrates the risk assessment process into field reporting, engineering, facility mapping, and other processes as necessary to ensure regular updates. [ASME B31.8S, §5.4]
iii. the integrity management plan calls for revision to the risk assessment process if pipeline maintenance or other activities identify inaccuracies in the characterization of the risk for any segments. [§192.917(c); ASME B31.8S, §5.12]
iv. the operator uses a feedback mechanism to ensure that the risk model is subject to continuous validation and improvement. [§192.917(c); ASME B31.8S, §5.7(f)]

e. **[PI]** Verify that adequate time and personnel have been allocated to permit effective completion of the selected risk assessment approach. [ASME B31.8S, §5.7(b)]

C.4 Validation of the Risk Assessment Verify that the integrity management program identifies and documents a process to validate the results of the risk assessments. [§192.917(c); ASME B31.8S, §5.12]

a. **[PI]** Verify that the validation process includes a check that the risk results are logical and consistent with the operator's and other industry experience. [§192.917(c); ASME B31.8S, §5.12]

C.5 Plastic Transmission Pipeline If the operator has plastic transmission pipelines, verify that the operator assesses applicable threats to each covered segment of plastic line. [§192.917(d)]

a. **[PI]** If the operator has plastic transmission lines, verify that the information in sections 4 and 5 of ASME B31.8S and any unique threats to the integrity of plastic pipe have been considered when assessing the threats to each covered segment of plastic pipeline. [§192.917(d)]

D. DA Plan

D.01 ECDA Programmatic Requirements If the operator elects to use ECDA, verify that the operator develops and implements an ECDA plan in accordance with §192.925.

a. **[P]** Verify that the operator developed a documented ECDA plan, and developed procedures to implement the plan. [§192.925(b)]

b. **[PI]** Verify that the operator applies more restrictive criteria when conducting ECDA for the first time on a covered segment. [§§192.925(b)(1)(i), (b)(2)(i), & (b)(3)(i)]

c. **[PI]** Verify that the operator's ECDA procedures have a process to address pipeline coating indications. The procedures must provide for integrating ECDA data with encroachment and foreign line crossing data to evaluate the covered segment for the threat of third party damage, and to address this threat as required by §192.917(e) (1) (See Protocol C.2 & C.3). [[§192.917(b) & (e) and §192.925 (b)]

D.02 ECDA Pre-Assessment Verify that the ECDA Pre-assessment process complies with ASME B31.8S §6.4 and NACE RP0502-2002 to (1) determine if ECDA is feasible for the pipeline to be evaluated, (2) identify ECDA regions and (3) select Indirect Inspection Tools. [§192.925(b)(1)]

a. **[PI]** Verify that the operator **identifies and collects adequate data** to support ECDA pre-assessment. [NACE RP0502 §3.2]

b. **[PI]** Verify that the operator conducts an ECDA **feasibility assessment** by integrating and analyzing the data collected. [NACE RP0502 § 3.3]

c. **[PI]** Verify that the operator complies with all requirements for appropriate indirect inspection **tools selection**: [NACE RP0502 § 3.4 & Table 2, & 192.925(b)(1)(ii)]

i. A minimum of 2 complementary tools must be selected such that the strengths of one tool compensate for the limitations of the other tool. (Note: The operator must consider whether more than two indirect inspection tools are needed to reliably detect corrosion activity.)
ii. Tools are able to assess and reliably detect corrosion activity and/or coating holidays.
iii. Verify that the operator documents the basis for its tool selection.
iv. If the operator utilizes an indirect inspection method not listed in Appendix A of NACE RP0502 verify that the operator justifies and documents the method's applicability, validation basis, equipment used, application procedure, and utilization of data. [§192.925(b)(1)(ii)]

d. **[PI]** Verify that the operator **identifies ECDA Regions** based on the use of data integration results applied to specified criteria. [NACE RP0502 §3.5]

D.03 ECDA Indirect Examination Verify that the ECDA Indirect Examination process complies with ASME B31.8S, Section 6.4 and NACE RP 0502-2002 Section 4 to identify and characterize the severity of coating fault indications, other anomalies, and areas at which corrosion activity may have occurred or may be occurring, and establish priorities for excavation. [§192.925(b)(2)]

a. **[PI]** Verify that the operator **conducts indirect examination measurements** in accordance with NACE RP0502, §4.2.

i. Verify that the operator identifies and clearly marks the boundaries of each ECDA region. [NACE RP0502 §4.2.1]
ii. Verify that the operator performs indirect inspections over the entire lengths of each ECDA region and that the inspections conform to generally accepted industry practices. [NACE RP0502 §4.2.2]
iii. Verify that the operator specifies and follows generally accepted industry practices for conducting ECDA indirect inspections and analyzing results. [NACE RP0502 §4.2.2]
iv. Verify that the operator specifies the physical spacing of readings (and the practices for changing the spacing as needed) such that suspected corrosion activity on the segment can be detected and located. [NACE RP0502 §4.2.3]

b. **[PI]** Verify that the operator properly aligns indications and compares the data from each indirect examination to characterize both the severity of indications and urgency for direct examination in accordance with NACE RP0502 §§4.3 & 5.2.

i. Verify the operator specifies criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum criteria include
   1. Known sensitivities of assessment tools
   2. The procedures for using each tool
   3. The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected. [§192.925(b)(2)(ii) & & NACE RP0502 §4.3.1.1]

ii. Verify that the operator specifies and applies criteria for classification of the severity of each indication. [NACE RP0502 §4.3.2],

   1. Verify that the operator considers the impact of spatial errors when aligning indirect examination results. [NACE RP0502 §4.3.1.2]
   2. Verify that the operator compares the results from the indirect inspections and determines the consistency of indirect inspections results to resolve conflicting or differing indications by the primary and secondary tools. [NACE RP0502 §4.3.3]
   3. Verify that the operator compares indirect inspection results with pre-assessment results to confirm or reassess ECDA feasibility and ECDA Region definitions. [NACE RP0502 §4.3.4]

iii. Verify that the operator specified and applies criteria for defining the urgency level (i.e., immediate, scheduled, or monitored) with which excavation and direct examination of indications will be conducted based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion. [§192.925(b)(2)(iii) & (iv) and NACE RP0502 §5.2]

D.04 ECDA Direct Examination Verify that the ECDA Direct Examination process complies with ASME B31.8S, Section 6.4 and NACE RP 0502-2002, Section 5 to collect data to assess corrosion activity and remediate defects discovered. [NACE RP 0502 §5.1.1 & §192.925(b)(3)]

a. **[PI]** Verify that the operator performs excavations and data collection in accordance with NACE RP0502 §§5.3, 5.4, 5.10, and 6.4.2.

i. Verify that the operator makes excavations based on priority categories described in §5.2 of RP0502. [NACE RP0502 §5.3.1]
ii. Verify that the operator identifies and implements minimum requirements for data collection, measurements, and recordkeeping, to evaluate coating condition and significant corrosion defects at each excavation location. [NACE RP0502 §§5.3, 5.4 & Appendices A, B, and C]
iii. Verify that the number and location of direct examinations complies with NACE RP0502 §§5.10 and 6.4.2

b. **[PI]** Verify that the operator determines the remaining strength at locations where corrosion defects are found. Any corrosion defects discovered during direct examinations must be remediated in accordance with §192.933. [§192.925(b)(3)(ii), 192.933, & NACE RP0502 §§5.5]

c. **[PI]** Verify that the operator identifies the root cause of all significant corrosion activity, [NACE RP0502 §5.6] and identifies and reevaluates all other indications that occur in the pipeline segment where similar root-cause conditions exist. [NACE RP0502 §5.9.3]

i. Verify that the operator considers alternative methods of assessing the integrity of the pipeline segment if the operator's root cause analysis uncovers problems for which ECDA is not well suited. [NACE RP0502 §5.6.2 & §192.925(b)(3)(ii)(b)]

d. **[P]** Verify that the operator mitigates or precludes future external corrosion resulting from significant root causes. [NACE RP0502 §5.7]

e. **[PI]** Verify that the operator performs an evaluation of the indirect inspection data, the results from the remaining strength evaluation and root cause analysis to evaluate the criteria and assumptions used to: [NACE RP0502 §5.8]
RP0502 §5.7 & 192.933]

i. Categorize the need for repairs,
ii. Classify the severity of individual indications,

f. **[PI]** As appropriate, verify the basis upon which the operator may reclassify and reprioritize indications in accordance with any of the provisions that are specified in §5.9 of NACE RP0502-2002. [§192.925(b)(3)(iv)]

g. **[PI]** Verify the operator establishes and implements criteria and internal notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications. [§§192.925(b)(3)(iii), 192.909, & 192.911(k)]

h. **[PI]** Verify that the operator has a process to consider the use of assessment methods other than ECDA (i.e., ILI or Subpart J pressure test) to assess the impact of defects other than external corrosion (e.g., mechanical damage and stress corrosion cracking) discovered during direct examination. [NACE RP0502 §5.1.5 & 192.933]

D.05 ECDA Post-Assessment Verify that the ECDA Post assessment process complies with ASME B31.8S, Section 6.4 and NACE RP 0502-2002, Section 6, to (1) define reassessment intervals and (2) assess the overall effectiveness of the ECDA process. [§§192.925(b)(4) & 192.939]

a. **[PI]** Verify that the operator determined **reassessment intervals** in accordance with NACE RP0502 §6.

i. Verify the adequacy of the operators remaining life calculations. [NACE RP0502 §6.2]
ii. Verify that the maximum re-assessment intervals for each region are one half the calculated remaining life. [NACE RP 0502 §§ 6.1.3 & 6.3]

b. **[PI]** Verify that the reassessment intervals are adjusted if required in accordance with special provisions in Subpart O, as follows:

i. Verify that reassessment intervals do not exceed the maximum intervals (refer to Protocol F) established in §192.939, as follows:
   1. 10 years for pipeline segments operating at SMYS levels greater than 50%
   2. 15 years for those segments operating between 30 and 50% SMYS
   3. 20 years for those segments operating below 30% SMYS
ii. Verify that the operator specifies and applies criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in §192.939. [§192.925(b)(4)(ii)]

c. **[PI]** Verify that performance measures for ECDA effectiveness have been defined and are monitored. [§§192.925 & 192.945(b) & NACE RP0502, Section 6]

i. Verify that at least one additional, randomly selected anomaly location has been excavated for process validation. [NACE RP0502, §6.4.2]

ii. Verify that additional criteria have been established and monitored to evaluate long-term program effectiveness such as those identified in § 6.4.3 of NACE RP0502. [§192.945(b) & NACE RP0502, §6.4.3]

d. **[PI]** Verify the operator's process has incorporated feedback at all appropriate opportunities throughout the ECDA process to demonstrate feedback and continuous improvement. [192.907(a) & NACE RP0502 §6.5]

D.06 Dry Gas ICDA Programmatic Requirements If the operator elects to use ICDA, verify that the operator develops and implements an ICDA plan in accordance with §192.927.

a. **[P]** Verify that the operator developed a documented ICDA plan [§192.927(c)]

b. **[P]** Verify that the operator's plan defines criteria to be applied in making key decisions (e.g., ICDA feasibility, ICDA Region identification, conditions requiring excavation) in implementing each stage of the ICDA process. [§192.927(c)(5)(i)]

c. **[P]** Verify that the operator's plan contains provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment [§192.927(c)(5)(ii)]

d. **[P]** Verify that the operator's plan contains provisions for carrying out ICDA on the entire pipeline in which covered segments are present, except that application of the remediation criteria of 192.933 may be limited to covered segments. [§192.927(c)(5)(iii)]

e. **[I]** Verify that the operator implements the ICDA plan. [§192.927(c)]

D.07 Dry Gas ICDA Pre-Assessment For dry gas systems, verify that the operator gathers, integrates and analyzes data and information to accomplish pre-assessment objectives and identify ICDA Regions. [§192.927(c)(1)& (2), ASME/ANSI B31.8S, §6.4.2 & Appendices A.2 & B.2]

a. **[PI]** Verify that the operator collects, as a minimum, the following **data and information**:

i. All data elements listed in ASME B31.8S Appendix A.2 [§192.927(c)(1)(i)]
ii. Information needed to support use of a model to identify areas where internal corrosion is most likely, including locations of all 1) gas input and withdrawal points, 2) low points such as sags, drips, inclines, valves, manifolds, dead-legs, and traps, 3) elevation profile in sufficient detail for angles of inclination to be calculated, and 4) the range of expected gas velocities within the pipeline; [§192.927(c)(1)(ii)]
iii. Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions [§192.927(c)(1)(iii)]
iv. Information where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes. [§192.927(c)(1)(iv)]

b. **[PI]** Verify that the operator integrates the data collected and uses the integrated data analysis to evaluate and document the following:

i. Feasibility of performing ICDA on its pipe segments [§192.927(c)(1)]
ii. Identification of all ICDA Regions and the location of each region. [§192.927(c)(1) & (2)]
iii. Support use of a model to identify the locations along the pipe segment where electrolyte may accumulate [§192.927(c)(1)]
iv. Identify areas within the covered segment where liquids may be potentially entrained. [§192.927(c)(1)]

c. **[PI]** Verify the operator's plan uses the model in GRI 02-0057 ICDA of Gas Transmission Pipelines- Methodology (or equivalent acceptable model) to define critical pipe angle of inclination above which water film cannot be transported by the gas, and that the model considers, as a minimum: [§192.927(c)(2)]

i. Changes in pipe diameter, [§192.927(c)(2)]
ii. Locations where gas enters a line, [§192.927(c)(2)]
iii. Locations down stream of gas draw-offs. [§192.927(c)(2)]
iv. Other conditions that may result in changes in gas velocity. [§192.927(c)(2) & GRI 02-0057]

D.08 Dry Gas ICDA Direct Examination For dry gas systems, verify that the operator (1) identifies locations where internal corrosion is most likely in each ICDA region and (2) performs direct examinations of those locations. [§192.927(b)& 192.927(c)(3), ASME B31.8S §6.4 and Appendix B.2]

a. **[PI]** Verify the operator has identified locations where internal corrosion is most likely to exist in each ICDA region and where electrolyte accumulation is predicted. [§192.927(c)(3) & ASME B31.8S §6.4.2 and Appendix B2.3]

b. **[PI]** Verify the operator requires a direct examination for internal corrosion using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique of those covered segment locations where internal corrosion is most likely to exist, and includes as a minimum, the following: [§192.927(c)(3) & ASME B31.8S §6.4.2 and Appendices B2.3 & B2.4]

i. A minimum of two (2) locations within each ICDA region within a covered segment,
ii. At least one location must be the low point (e.g., sags, drips, valves, manifolds, deadlegs, traps) nearest the beginning of the ICDA region and
iii. The second location must be further downstream within a covered segment near the end of the ICDA Region (The end of the ICDA region is the farthest downstream location where the ICDA model predicts electrolytes could accumulate based on the critical angle of inclination above which water film cannot be transported by the gas). [§192.927(c)(2) & ASME B31.8S, Appendix B2.3]

c. **[PI]** If internal corrosion exists at any location directly examined, verify that the operator: [192.927(c)(3)]

i. Evaluates the severity of the defect and remediates the defect per §192.933 (see Protocol E) [§192.927(c)(3)(i)], and
ii. Either performs additional excavations or performs additional assessment using an allowed alternative assessment method [§192.927(c)(3)(ii)], and
iii. Evaluates the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found and remediates the conditions per §192.933. [§192.927(c)(3)(iii)]

D.09 Dry Gas ICDA Post-Assessment For dry gas systems, verify that the operator performs post-assessment evaluation of ICDA effectiveness and continued monitoring of covered segments where internal corrosion has been identified. [§192.927(c)(4)]

a. **[PI]** Verify the operator has a process for **evaluating the effectiveness** of ICDA as an assessment method and **determining reassessment intervals**. [§192.927(c)(4)(i) & ASME B31.8S Appendix B2.5]

i. Verify that if corrosion is found in areas where the pipeline inclination is greater than the estimated critical inclination, that the operator re-evaluates the critical inclination angle and additional new areas are selected for direct examination. [ASME B31.8S Appendix B2.5]
ii. Verify the operator's process determines whether a segment must be reassessed at intervals more frequently than those specified in §192.939 using the largest defect most likely to remain in the covered segment as the largest defect discovered in the ICDA segment and estimating the reassessment interval as half the time required for the largest defect to grow to critical size. Verify that this evaluation is to be carried out within one year of completion of the assessment. [§192.927(c)(4)(i) & §192.939(a)(3)]
iii. Verify the operator's reassessment intervals comply with the following maximum allowed intervals in accordance with 192.939 (see Protocol F). [§192.939(b)]
   1. 10 years for segments operating at SMYS levels greater than 50%
   2. 15 years for segments operating between 30 and 50% SMYS
   3. 20 years for segments operating below 30% SMYS

b. **[PI]** Verify the operator continually monitors each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing them for corrosion products. [§192.927(c)(4)(ii)]

i. Verify the operator has a process to determine the frequency for monitoring and liquid analysis based on all integrity assessments results conducted in accordance with 192 Subpart O and risk factors specific to the covered segment. [§192.927(c)(4)(ii), ASME B31.8S Appendix A2.2]

ii. Verify the operator's process requires that if any evidence of corrosion products is found in the covered segment, prompt action must be taken including, as a minimum: [§192.927(c)(4)(ii)]

1. Remediate the conditions the operator finds in accordance with §192.933, and
2. Implement one of the two following required actions: (1) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe, or (2) assess the covered segment using another integrity assessment method allowed by Subpart O.

D.10 Wet Gas ICDA Programmatic Requirements – If the operator elects to use ICDA to assess a covered segment operating with electrolyte present in the gas stream (wet gas), verify that the operator develops and implements an ICDA plan in accordance with §192.927 which addresses the following. [§192.927(b)]

a. **[P]** Verify that the operator developed a documented ICDA plan which demonstrates how the operator will conduct ICDA on the entire pipeline in which covered segments are present to effectively address internal corrosion. [§192.927(c)]

b. **[PI]** Verify the operator has provided notification to OPS of an ICDA wet gas "other technology" application in accordance with §192.921 (a) (4) or §192.937 (c) (4). [§192.927(b)]

D.11 SCCDA Data Gathering & Evaluation Verify that the operator's SCCDA evaluation process complies with ASME/ANSI B31.8S, Appendix A3 in order to identify whether conditions for SCC of gas line pipe are present and to prioritize the covered segments for assessment. [§192.929(b)(1)]

a. **[PI]** Verify that the operator has a process to **gather, integrate, and evaluate data** for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. [192.929(b)(1)]

i. Verify that the operator's gathers and evaluates data related to SCC at all sites it excavates during the conduct of its pipeline operations (not just covered segments) where the criteria indicate the potential for SCC. [192.929(b)(1) & ASME/ANSI B31.8S, Appendix A3.3]

ii. Verify that the data includes, as a minimum, the data specified in ASME/ANSI B31.8S, Appendix A3.

iii. Verify that the operator addresses missing data by either using conservative assumptions or assigning a higher priority to the segments affected by the missing data, as required by ASME/ANSI B31.8S, Appendix A3.2.

D.12 SCCDA Assessment, Examination, & Threat Remediation Verify that covered segments (for which conditions for SCC are identified) are assessed, examined, and the threat remediated. [§192.929(b)(2)]

a. **[PI]** Verify that, if conditions for SCC are present, that the operator **conducts an assessment** using one of the methods specified in ASME/ANSI B31.8S, Appendix A3.

b. **[PI]** Verify that the operator's plan specifies an acceptable **inspection, examination, and evaluation plan** using either the Bell Hole Examination and Evaluation Method (that complies with all requirements of ASME B31.8S Appendix A3.4 (a)) or Hydrostatic Testing (that complies with all requirements of A3.4 (b)).

i. Verify, that the operator's plan requires that for pipelines which have experienced an in-service leak or rupture attributable to SCC, that the particular segment(s) be subjected to a hydrostatic pressure test (that complies with ASME/ANSI B31.8S, Appendix A3.4 (b)) within 12 months of the failure, using a documented hydrostatic retest program developed specifically for the affected segment(s), as required by ASME/ANSI B31.8S, Appendix A3.4.

c. **[PI]** Verify that assessment results are used to determine **reassessment intervals** in accordance with §192.939(a)(3); (see Protocol F). [§192.939(a)(3)]

E. Remediation

E.1 Program Requirements for Discovery, Evaluation and Remediation Scheduling Verify that provisions exist to discover and evaluate all anomalous conditions resulting from integrity assessment and remediate those which could reduce a pipeline's integrity. [§192.933(a)]

a. **[P]** Verify a definition of discovery is provided. [§192.933(b)]

b. **[P]** Verify a requirement exists to document the actual date of discovery. [§192.933(b)]

c. **[P]** Verify a requirement exists to develop a schedule that prioritizes evaluation and remediation of anomalous conditions. [§192.933(c)]

d. **[P]** If the operator desires to deviate from the timelines for remediation as provided in §192.933 by demonstrating exceptional performance, verify that the requirements of §192.913(b) have been met and the safety of the covered segment is not jeopardized. [§192.913(c)(2)](See Protocol F.5)

E.2 Program Requirements for Identifying Anomalies Inspect the operator's program to verify that provisions exist for the classification and remediation of anomalies that meet the criteria for: (1) Immediate repair conditions; (2) One-year conditions; (3) Monitored conditions; or (4) Other conditions as specified in ASME/ANSI B31 8S, Section 7 . [§§ 192.933(c) & 192.933(d)]

a. **[P]** Verify the program requires a temporary pressure reduction or the pipeline to be shut down upon discovery of all immediate repair conditions. [§192.933(d)(1)]

b. **[P]** Verify provisions exist to classify and categorize anomalies meeting the following criteria:

i. Immediate Repair Conditions (Conditions requiring immediate remediation actions)
   1. Calculated remaining strength indicates a failure pressure that is less than or equal to 1.1 times MAOP; [192.933(d)(1)]
   2. A dent having any indication of metal loss, cracking, or a stress riser; [192.933(d)(1)]
   3. An indication or anomaly that is judged by the person designated by the operator to evaluate assessment results as requiring immediate action. [192.933(d)(1)]
   4. Metal-loss indications affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding; [ASME B31.8S, Section 7.2.1]
   5. All indications of stress corrosion cracks; [ASME B31.8S, Section 7.2.2]; or

6. Any indications that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. [ASME B31.8S, Section 7.2.3]

ii. One-Year Conditions (Conditions requiring remediation within one year of discovery).

1. A smooth dent located between the 8 and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter; [192.933(d)(2)] or,
2. A dent with a depth greater than 2% of the pipeline's diameter, that affects pipe curvature at a girth weld or at a longitudinal seam weld. [192.933(d)(2)]

iii. Monitored Conditions (Conditions which must be monitored until the next assessment).

1. A dent with a depth greater than 6% of the pipeline diameter located between the 4 and 8 o'clock position (lower 1/3) of the pipe; [192.933(d)(3)]
2. A dent located between the 8 and 4 o'clock position (upper 2/3) of the pipe with a depth greater than 6% of the pipeline diameter, and engineering analysis to demonstrate critical strain levels are not exceeded; [192.933(d)(3)]or,
3. A dent with a depth greater than 2% of the pipeline diameter, that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analysis of the dent and girth or seam weld to demonstrate critical strain levels are not exceeded. [§192.933(d)(3)]

c. **[P]** Verify provisions exist to record and monitor anomalies that are classified as "monitored conditions" during subsequent risk or integrity assessments for any change in their status that would require remediation. [§192.933(d)(3)]

d. **[P]** Verify that program requirements exist to meet the provisions of ASME/ANSI B31.8S, Section 7, Figure 4 for scheduling and remediating any other threat conditions that do not meet the classification criteria of E.2.b, above. [§192.933(c)]

E.3. Operator Response when Timelines for Evaluation and Remediation Cannot be Met Verify that provisions exist to respond appropriately when the operator is unable to meet time limits for evaluation and remediation. [§192.933(a)].

a. **[P]** Verify a requirement exists to take a temporary operating pressure reduction or other action that ensures safety of the covered segment in the event the operator is unable to respond within the timeframes required by §192.933. [§192.933(a)]

i. Verify a requirement exists to determine the appropriate pressure reduction using ASME/ANSI B31G, or "RSTRENG", or reduce pressure to a level not exceeding 80% of the level at the time the condition was discovered. [§192.933(a)]

ii. Verify a requirement exists that when a pressure reduction is to exceed 365 days, a documented technical justification is developed that demonstrates continuation of the reduction will not jeopardize pipeline integrity. [§192.933(a)]

b. **[P]** Verify a requirement exists to document the justification, when a remediation activity cannot be completed within established timeframe requirements, that includes the reasons why the schedule cannot be met and the basis for why the changed schedule will not jeopardize public safety. [§192.933(c)]

c. **[P]** Verify a requirement exists to notify OPS in accordance with Section 192.949 or the State or local pipeline safety authority, if applicable, when the operator cannot meet the schedule and cannot provide a temporary reduction in operating pressure or other action. [§192.933(c)]

E.4. Record Review for Discovery, Repair and Remediation Activities Inspect operator repair and remediation records to verify that remediation activities have been conducted in accordance with program requirements. [§192.933]

a. **[I]** Verify a prioritized schedule exists for evaluation and remediation of anomalies identified during assessment or reassessment activities. The prioritized schedule must document which of the criteria specified in §192.933(d) and/or ASME/ANS B31.8S were used as the basis for the schedule. [§§192.933(c) & 192.933(d)]

b. **[I]** Verify anomaly discovery was documented within 180 days of completion of the assessment or reassessment, or else that compliance with the 180-day period was impracticable. [§192.933(b)]

c. **[I]** Verify any remediation activities taken are sufficient to ensure that the anomaly is unlikely to threaten the integrity of the pipeline before the next scheduled reassessment. [§192.933(a)]

d. **[I]** Verify, for any immediate repair anomalies, a temporary pressure reduction is taken by the operator on the pipeline and the reduced pressure is determined in accordance with ASME/ANSI B31G, or "RSTRENG", or that the reduced pressure does not exceed 80% of the level at the time the condition was discovered. [§192.933(a)]

e. **[I]** Verify immediate repair conditions have been evaluated and remediated on a schedule established in accordance with the provisions of ASME B31.8S, Section 7. [§192.933(d)(1)]

f. **[I]** Verify any pressure reduction taken has not exceeded 365 days from the date of discovery unless a technical justification has been developed to demonstrate that continuation of the pressure reduction will not jeopardize the integrity of the pipeline. [§192.933(a)]

g. **[I]** Verify that remediation activities were completed in accordance with scheduled timeframes. [§§192.933(c) & 192.933(d)]

h. **[I]** Verify that anomalies meeting any of the criteria of 192.933(d)(3) as "monitored conditions" are evaluated during subsequent risk and integrity assessments to identify any change that may require remediation and that any required remediation is scheduled and implemented in accordance with the applicable requirements of 192.933 and ASME B31.8S [§192.933(d)]

i. **[I]** Verify any remediation activities that have not been completed in accordance with §192.933 timeframes, and the operator has not provided safety through a temporary pressure reduction, have been reported to OPS and appropriate State or local authorities in accordance with the requirements of §192.933(c) of the rule. [§192.933(c)]

F. Continual Evaluation and Assessment

F.1 Periodic Evaluations Verify the operator conducts a periodic evaluation of pipeline integrity based on data integration and risk assessment to identify the threats specific to each covered segment and the risk represented by these threats. [§192.917, 192.937(b)]

a. **[PI]** Verify that periodic evaluations are conducted based on a data integration and risk assessment of the entire pipeline as specified in §192.917. The evaluation must consider the following: [§192.937(b), 192.917]

i. Past and present assessment results
ii. Data integration and risk assessment information [§192.917]
iii. Decisions about remediation [§192.933]
iv. Additional preventive and mitigative actions [§192.935]

b. **[I]** Verify that periodic evaluations of data are thorough, complete, and adequate for establishing reassessment methods and schedules. [§192.937(b)]

c. **[PI]** Verify that an appropriate interval is established for performing required periodic evaluations of threats and pipeline conditions following completion of the baseline assessment. [§192.937(b)]

d. **[PI]** Verify that the operator periodically reviews the evaluation results to determine if the new information warrants changes to reassessment intervals and/or methods, and makes changes as appropriate. [§192.937]

F.2 Reassessment Methods Verify that the approach for establishing the reassessment method is consistent with the requirements in §192.937(c). [§192.937(c), 192.941]

a. **[PI]** Verify that one or more of the following assessment methods (depending on the applicable threats) are specified:

i. An internal inspection tool(s) capable of detecting corrosion and any other threats that the operator intends to address using this tool(s). The process must follow ASME/ANSI B31.8S, Section 6.2 in selecting the appropriate inspection tool. [§192.937(c)(1)]
ii. A pressure test conducted in accordance with subpart J. 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. Pressure test is appropriate for threats as defined in ASME/ANSI B31.8S, section 6.3. [§192.937(c)(2)]
iii. Direct assessment – refer to Protocol D. [§192.937(c)(3)]
iv. Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the pipe. If other technology is the method selected, the process should require that the operator notify OPS at least 180 days before conducting the assessment, in accordance with 192.949. Also, verify that notification to a State or local pipeline safety authority is required 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. [§192.937(c)(4)]

v. Confirmatory direct assessment when used on a covered segment that is scheduled for a reassessment period longer than seven years. Refer to Protocol G. [§192.937(c)(5)]

vi. If the operator is using "low stress reassessment" method, evaluate the process using protocol question F.3.

b. **[I]** Review the methods selected for reassessments and verify that they are appropriate for the identified threats.

F.3 Low Stress Reassessment For pipelines operating at < 30% SMYS, the operator may choose to use a "low stress reassessment" method to address threats of external and internal corrosion. If this method is used, verify that the operator addresses the following requirements [§192.941]:

a. **[PI]** Verify that the operator completes a baseline assessment on the covered segment prior to implementing the "low stress reassessment" method. [§192.941(a)]

b. **[PI]** If used to address external corrosion, verify that the operator has incorporated the following:

i. If the pipe is cathodically protected, electrical surveys (i.e., indirect examination tool/method) must be performed at least every 7 years. The operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for covered segments. This evaluation must consider, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe records, and the pipeline environment. [§192.941(b)(1)]

ii. If the pipe is unprotected or cathodically protected where electrical surveys are impractical, the operator must require (1) the conduct of leakage surveys as required by 192.706, at 4-month intervals; and (2) the identification and remediation of areas of active corrosion every 18 months by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe records, and the pipeline environment. [§192.941(b)(1)]

c. **[PI]** If used to address internal corrosion, verify that the operator has incorporated all of the following:

i. Gas analysis for corrosive agents must be performed at least once each calendar year. [§192.941(c)(1)]

ii. Periodic testing of fluids removed from the segment must be conducted. At least once each calendar year the operator must test the fluids removed from each storage field that may affect a covered segment. [§192.941(c)(2)]

iii. At least every seven (7) years, the operator must integrate data from the analysis and testing required by c.i and c.ii above with applicable internal corrosion leak records, incident reports, and test records, and define and implement appropriate remediation actions. [§192.941(c)(3)]

F.4 Reassessment Intervals Verify that the requirements for establishing the reassessment intervals are consistent with section §192.939 and ASME B31.8S. [§ 192.937(a), 192.939(a), 192.939(b), 192.913(c), ASME B31.8S-2001, section 5, Table 3]

a. **[PI]** Verify that the operator reassesses covered segments on which a baseline assessment was conducted during the baseline period specified in subpart 192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the reassessment evaluation (refer to question F.1) indicates an earlier reassessment. [§192.937(a)]

b. **[PI]** For pipelines operating at or above 30% SMYS, verify that the operator meets the following requirements:

i. If the operator establishes a reassessment interval greater than seven (7) years, a confirmatory direct assessment (refer to Protocol G) must be performed at intervals not to exceed seven (7) years followed by a reassessment at the interval established by the operator (refer below). [§192.939(a)]

ii. Unless a deviation is permitted under 192.913(c), the maximum reassessment interval shall not exceed the values listed in the 192.939(b) table. [§192.937(a)]

iii. If the reassessment method is a pressure test, ILI, or other equivalent technology, the interval must be based on either: (1) the identified threat(s) for the covered segment (see §192.917) and on the analyses of the results from the last integrity assessment, and a review of data integration and risk assessment; or (2) using the intervals specified for different stress levels of pipeline listed in ASME/ANSI B31.8S, section 5, Table 3. 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. [§192.939(a)(1)]

iv. If the reassessment method is external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment refer to Protocol D for evaluating the operator’s interval determination.

c. **[PI]** For pipelines operating < 30% SMYS, verify that the operator selects one of the following reassessment approaches:

i. Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph 192.939(a)(1) except that the stress level referenced in 192.939(a)(1)(ii) would be adjusted to reflect the lower operating stress level. However, if an established interval is more than seven (7) years, the operator must conduct at seven (7) year intervals either a confirmatory direct assessment in accordance with 192.931, or a low stress reassessment in accordance with 192.941. 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.[§192.939(b)(1)]

ii. Reassessment by external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment. Refer to Protocol D for evaluating the operator’s interval determination. [§192.939(b)(2), (b)(3), (b)(4)]

iii. Reassessment by confirmatory direct assessment at seven year intervals in accordance with subpart 192.931, with reassessment by one of the methods listed in 192.939(b)(1) – (b)(3) by year 20 of the interval. [§192.939(b)(4)]

iv. Reassessment by the "low stress method" at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in 192.939(b)(1) through (b)(3) by year 20 of the interval. [§192.939(b)(5)]

d. **[PI]** Verify that a covered segment on which a prior assessment was credited as a baseline assessment under subpart 192.921(e) is required to be reassessed by no later than December 17, 2009. [§192.937(a)]

e. **[I]** Verify that reassessment intervals are appropriate and that adequate documentation and technical bases support the intervals selected.

F.5 Deviation From Reassessment Requirements If the operator elects to deviate from certain requirements listed in §192.913(c), verify that the operator uses a performance based approach that satisfies the requirements for exceptional performance as follows: [§192.913, ASME/ANSI B31.8S]

a. **[PI]** Verify that the operator has a performance based integrity management program that meets or exceeds the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements: [§192.913(a)]

i. A comprehensive process for risk analysis;
ii. All risk factor data used to support the program;
iii. A comprehensive data integration process;
iv. A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;
v. A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;
vi. A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments (Refer to Protocol I);
vii. Semi-annual performance measures beyond those required in §192.943 that are part of the operator's performance plan. [See §192.911(i)] Refer to Protocol I.
viii. An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

b. **[PI]** Verify that the operator has completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach and is able to demonstrate that each assessment effectively addressed the identified threats on the covered segments. [§192.913(b)(2)(i)]

c. **[PI]** Verify the operator has remediated anomalies identified in the more recent assessment per the requirements of §192.933. [§192.913(b)(2)(ii)]

d. **[PI]** Verify the operator has incorporated the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment. [§192.913(b)(2)(ii)]

e. **[PI]** Verify that deviations are allowed only for the timeframe for reassessment as provided in §192.939 except that reassessment by some method allowed by Subpart O (e.g., confirmatory direct assessment) must be completed at intervals not to exceed seven (7) years. [§192.913(c)(1)]

F.6 Waiver from Reassessment Interval Verify that the operator's program requires that it apply for a waiver, should it become necessary, from the required reassessment interval. The waiver request must demonstrate that the waiver is justified as specified in the rule. Such a waiver request may only be made in the following limited situations: [§192.943]

a. **[PI]** Lack of internal inspection tools. [§192.943(a)(1)]

b. **[PI]** Cannot maintain local product supply. [§192.943(a)(2)]

c. **[PI]** Application must be made at least 180 days before the end of the required reassessment interval. (Exception: If local product supply issues make the 180 day submittal impractical, an operator must apply for the waiver as soon as the need for waiver becomes known). [§192.943(b)]

F.7 Consideration of Environmental and Safety Risks Verify that the operator addresses requirements for conducting the reassessments in a manner that minimizes environmental and safety risks. [§192.911(o)]

a. **[PI]** Verify that precautions were implemented to protect workers, members of the public, and the environment from safety hazards (such as an accidental release of product) during reassessments. [§192.911(o)]

G. Confirmatory DA

G.1 Confirmatory Direct Assessment, CDA If using confirmatory direct assessment (CDA) as allowed in §192.937, verify that the operator's integrity management plan meets the requirements of §192.931, §192.925 (ECDA) and §192.927 (ICDA). [§192.931]

a. **[P]** Verify that the operator is applying CDA to identify damage resulting from external corrosion or internal corrosion only. [§192.931(a)]

b. **[P]** Verify that the operator's CDA plan for external corrosion complies with all of the requirements contained in §192.925 (See Protocols D.1 ~ D.5) with the following exceptions, [§§192.931(b) & 192.925]

i. The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application

ii. The procedures for direct examination and remediation must provide that all immediate action indications and at least one scheduled action indication are excavated for each ECDA region.

c. **[P]** Verify that the operator's CDA plan for internal corrosion complies with all of the requirements contained in §192.927 (See Protocols D.6 ~ D.9) except that procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.[§§192.931(c) & 192.925]

d. **[PI]** When using CDA carried out under §192.931(b) or (c), if an operator discovers any defect requiring remediation prior to the next scheduled assessment, verify that the operator evaluates the need to accelerate the schedule for the next assessment. If the schedule is accelerated, verify that the new assessment scheduled is determined using the methodology documented in NACE RP0502-2002, Section 6.2 and 6.3. [§192.931(d)]

i. If the defect requires immediate remediation, verify the operator reduces pressure consistent with §192.933 (See Protocol E) until the operator has completed reassessment using one of the assessment techniques allowed in §192.937 (See Protocol F). [§192.931(d)]

H. Preventive and Mitigative Measures

H.1 General Requirements (Identification of Additional Measures) Verify that a process is in place to identify additional measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. [§192.935(a)]

a. **[P]** Verify that the process for identifying additional measures is based on identified threats to each pipeline segment and the risk analysis required by §192.917. [Note: Protocol H.8 addresses the implementation decision process for additional preventive and mitigative measures.] [§192.935(a)]

b. **[P]** Verify that additional measures evaluated by the operator cover a spectrum of alternatives such as, but 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. [§192.935(a)]

H.2 Third Party Damage Verify that the following preventive and mitigative requirements regarding threats due to third party damage have been addressed: [§192.935(b)(1), §192.935(e)(1)]

a. **[PI]** Verify implementation of enhancements to the §192.614-required Damage Prevention Program with respect to covered segments to prevent and minimize the consequences of a release, and that the enhanced measures include, at a minimum: [Note: As noted in Protocol H.3 and Protocol H.4, a subset of these enhancements are required for pipelines operating below 30% SMYS and for plastic transmission pipelines.] [§192.935(b)(1)]

- i. Using qualified personnel (see Protocol L.2 - §192.915(c)) 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. [§192.935(b)(1)(i)]
- ii. Collecting, in a central database, location-specific information 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. [§192.935(b)(1)(ii)]
- iii. Participating in one-call systems in locations where covered segments are present. [§192.935(b)(1)(iii)]
- iv. Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. [§192.935(b)(1)(iv)]
  1. When there is physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, verify that the area near the encroachment must be excavated or that an above ground

survey using methods defined in NACE RP-0502-2002 must be conducted. [§192.935(b)(1)(iv)]

A. If an above ground survey is conducted, verify that any indication of coating holidays or discontinuities warranting direct examination must be excavated and remediated in accordance with ANSI/ASME B31.8S Section 7.5 and §192.933. [§192.935(b)(1)(iv)]

b. **[PI]** If the threat of third party damage is identified by results of the §192.917(b) (Protocol C.2) and ASME/ANSI B31.8S Appendix A7 data integration processes, verify that comprehensive additional preventive measures are implemented. [§192.917(e)(1)]

H.3 Pipelines Operating Below 30% SMYS Verify that the following preventive and mitigative requirements for pipelines operating below 30% SMYS have been addressed: [§192.935(d)]

a. **[PI]** For pipelines operating below 30% SMYS located in a high consequence area:

i. Verify that the operator's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.2 - §192.915(c)) 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. [§192.935(d), §192.935(d)(1)] [Note: This requirement is also contained in previous Protocol H.2.a.i for pipelines operating above 30% SMYS.]

ii. Verify that the operator's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. [§192.935(d), §192.935(d)(1)] [Note: This requirement is also contained in previous Protocol H.2.a.iii for pipelines operating above 30% SMYS.]

iii. Verify that excavations near the pipeline are monitored, or patrols are conducted of the pipeline at bi-monthly intervals as required by §192.705. [§192.935(d), §192.935(d)(2)]

1. If indications of unreported construction activity are found, verify that required follow up investigations are conducted to determine if mechanical damage has occurred. [§192.935(d)(2)]

b. **[PI]** For pipelines operating below 30% SMYS located in a class 3 or 4 area but not in a high consequence area:

i. Verify that the operator's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.2 - §192.915(c)) 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. [§192.935(d), §192.935(d)(1), Table

E.II.1] [Note: This requirement is also contained in previous Protocol H.2.a.i for pipelines operating above 30% SMYS.]

ii. Verify that the operator's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. [§192.935(d), §192.935(d)(1), Table E.II.1] [Note: This requirement is also contained in previous Protocol H.2.a.iii for pipelines operating above 30% SMYS.]

iii. Verify that excavations near the pipeline are monitored, or patrols are conducted of the pipeline at bi-monthly intervals as required by §192.705. [§192.935(d), §192.935(d)(2), Table E.II.1]

1. If indications of unreported construction activity are found, verify that required follow up investigations are conducted to determine if mechanical damage has occurred. [§192.935(d)(2), Table E.II.1]

iv. Verify that the operator performs semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical). [§192.935(d)(3), Table E.II.1]

H.4 Plastic Transmission Pipeline For plastic transmission pipelines, verify that applicable third party damage requirements have been applied to covered segments of the pipeline. [§192.935(e)]

a. **[PI]** Verify that the operator’s processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.2 - §192.915(c)) 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. [§192.935(e)] [Note: This requirement is also contained in previous Protocol H.2.a.i for non-plastic pipelines operating above 30% SMYS.]

b. **[PI]** Verify that the operator's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. [§192.935(e)] [Note: This requirement is also contained in previous Protocol H.2.a.iii for non-plastic pipelines operating above 30% SMYS.]

c. **[PI]** Verify that the excavations on covered segments are monitored by pipeline personnel. [§192.935(e)] [Note: This requirement is also contained in previous Protocol H.2.a.iv for non-plastic pipelines operating above 30% SMYS.]

i. When there is physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, verify that the area near the encroachment must be excavated or that an above ground survey using methods defined in NACE RP-0502-2002 must be conducted. [§192.935(e)] [Note: This requirement is also contained in previous Protocol H.2.a.iv for non-plastic pipelines operating above 30% SMYS.]

1. If an above ground survey is conducted, verify that any indication of coating holidays or discontinuities warranting direct examination must be excavated and remediated in accordance

with ANSI/ASME B31.8S Section 7.5 and §192.933. [§192.935(e)] [Note: This requirement is also contained in previous Protocol H.2.a.iv for non-plastic pipelines operating above 30% SMYS.]

H.5 Outside Force Damage Verify that the operator adequately addresses threats due to outside force (e.g., earth movement, floods, unstable suspension bridge). [§192.935(b)(2)]

a. **[PI]** If the operator makes a determination that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment (e.g., via Protocol C.1 activities), verify that measures have been taken to minimize the consequences to the covered segment. 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. [§192.935(b)(2)]

H.6 Corrosion Verify that the operator takes required actions to address corrosion threats. [§192.917(e)(5)]

a. **[PI]** Verify that the operator makes a determination of whether or not corrosion exists on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933). [§192.917(e)(5)]

i. If such corrosion is identified, then verify that:
1. The corrosion is evaluated and remediated, as necessary, for all pipeline segments (both covered and noncovered) with similar material coating and environmental characteristics. [§192.917(e)(5)]
2. A schedule is established for evaluating and remediating, as necessary, the similar segments consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair. [§192.917(e)(5)]

H.7 Automatic Shut-Off Valves or Remote Control Valves Verify that the operator has a process to decide if automatic shut-off valves or remote control valves represent an efficient means of adding protection to potentially affected high consequence areas. [§192.935(c)]

a. **[PI]** Verify that an adequate risk analysis-based process is used to determine if an automatic shut-off valve or remote control valve should be added. [§192.935(c)]

i. Verify that, as a minimum, the following factors were considered: [§192.935(c)]
1. swiftness of leak detection and pipe shutdown capabilities
2. the type of gas being transported
3. operating pressure
4. the rate of potential release
5. pipeline profile
6. the potential for ignition
7. location of nearest response personnel

H.8 General Requirements (Implementation of Additional Measures) Verify that the operator has identified and implemented (or scheduled) 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: [§192.935(a)]

a. **[P]** Verify that a systematic, documented decision-making process is in place to decide which measures are to be implemented, involving input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control. [§192.935(a)]

b. **[P]** Verify that the decision-making process considers both the likelihood and consequences of pipeline failures. [§192.935(a)]

c. **[I]** Verify that additional measures are identified and documented and have actually been implemented, or scheduled for implementation. [§192.935(a)]

I. Performance Measures

I.1. General Performance Measures Inspect the operator's program to verify that, as a minimum, provisions exist for measuring integrity management program effectiveness in accordance with the four elements of ASME/ANSI B31.8S, Section 9.4 and each identified threat in ASME/ANSI B31.8S, Appendix A. [§192.945(a) and ASME B31.8S, §12(b)(5)]

a. **[PI]** Verify that performance is measured semi-annually (completed through June 30th and December 31st of each year) for each of the following: [ASME B31.8S, §9.4]

- Number of miles of pipeline inspected versus program requirements
- Number of immediate repairs completed as a result of the integrity management inspection program
- Number of scheduled repairs completed as a result of the integrity management program
- Number of leaks, failures and incidents (classified by cause).

b. **[PI]** Verify that performance is measured semi-annually in accordance with the threat-specific metrics of ASME/ANSI B31.8S, Appendix A (See Table 9 in ASME/ANSI B31.8S for a summary listing).

I.2 Performance Measures Records Verification Inspect operator records to verify: [§ 192.945(a)]

a **[PI]** The four overall performance measures of ASME B31.8S, § 9.4 have been submitted to OPS on a semi-annual basis in accordance with § 192.951. Note: Initial report by August 31, 2004, semi-annual reports by February 28th (or 29th) and August 31st of each year thereafter. [§ 192.945(a)]

I.3 Exceptional Performance Measurements For operators that choose to demonstrate exceptional performance in order to deviate from certain requirements of the rule, verify the following.

a. **[PI]** Additional performance measures beyond those required in §192.945 (see Protocol I.1) are part of the operator's performance plan. [§192.913(b)(vii)]

b. **[PI]** All performance measures (all measures required by §192.945 and the additional performance measures) are submitted to OPS on a semi-annual frequency in accordance with §192.951. [§192.913(b)(vii)]

J. Record Keeping

J.1 Records to be Maintained by the Operator Verify that the following records, as a minimum, are maintained for the useful life of the pipeline: [§192.947, ASME B31.8S,§§ 12.1 & 12.2(b)(1)]

a. **[PI]** A written integrity management program [§192.947(a)]

b. **[PI]** Threat identification and risk assessment documentation per §192.917 [§192.947(b)]

c. **[PI]** A written baseline assessment plan per §192.919 [§192.947(c)]

d. **[PI]** Documents to support any decision, analysis, and process 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 [§192.947(d)]

e. **[PI]** Training program documentation and training records per §192.915 [§192.947(e)]

f. **[PI]** Remediation schedule and technical basis documentation per §192.933 [§192.947(f)]

g. **[PI]** Direct assessment plan documentation per §192.923 through §192.929 [§192.947(g)]

h. **[PI]** Confirmatory assessment documentation per §192.931 [§192.947(h)]

i. **[PI]** Documentation of Notifications to OPS or State/Local Regulatory Agencies. [§192.947(i)]

K. Management of Change (MOC)

K.1. Documentation and Notification of Changes to the Integrity Management Program Verify that changes to the integrity management program have been handled in accordance with §192.909 of the rule.

a. **[P]** Verify that the reasons for program changes have been documented prior to implementation of the change(s). [§192.909(a)]

b. **[P]** Verify, that for significant changes to the program, program implementation, or schedules, OPS or the State or local pipeline safety authority, if applicable, has been notified within 30 days after the operator has adopted the change. [§192.909(b)]

K.2 Attributes of the Change Process Verify that the integrity management program meets the requirements of ASME/ANSI B31.8S, Section 11 for a management of change process. [§192.911(k)]

a. **[PI]** Verify the existence of procedures that consider impacts of changes to pipeline systems and their integrity. [ASME B31.8S, §11(a)]

b. **[PI]** Verify change procedures address technical, physical, procedural, and organizational changes. [ASME B31.8S, §11(a)]

c. **[PI]** Verify the following are provided for by the change procedures: [ASME B31.8S, §11(a)]

i. Reason for change
ii. Authority for approving changes
iii. Analysis of implications
iv. Acquisition of required work permits
v. Documentation
vi. Communication of the change to affected parties
vii. Time limitations
viii. Qualification of staff

d. **[PI]** Verify that integrity management system changes are properly reflected in the pipeline system and that pipeline system changes are properly reflected in the integrity management program. [ASME B31.8S, §11(b)]

e. **[I]** Verify that equipment or system changes have been identified and reviewed before implementation. [ASME B31.8S, §11(d)]

f. **[I]** Verify that the risk assessment process and outputs have included changes to applicable data. [§192.917(c) and ASME B31.8S, Section 5.4]

L. Quality Assurance

L.1 Program Requirements for the Quality Assurance Process Verify that a quality assurance process exists that meets the requirements of ASME/ANSI B31.8S, section 12. [§192.911(l)]

a. **[P]** Verify that responsibilities and authorities for the integrity management program have been formally defined. [ASME B31.8S, §12.(b)(2)]

b. **[P]** Verify that reviews of the integrity management program and the quality assurance program have been specified to be performed on regular intervals, making recommendations for improvement. [ASME B31.8S, §12(b)(3)]

c. **[PI]** Verify that corrective actions to improve the integrity management program and the quality assurance process have been documented and are monitored for effectiveness. [ASME B31.8S, §12(b)(7)]

d. **[]** Verify that when an operator chooses to use outside resources to conduct any process that affects the quality of the integrity management program, the operator ensures the quality of such processes and documents them within the quality program. [ASME B31.8S, §12.2(c)]

L.2 Personnel Qualification and Training Requirements Verify that personnel involved in the integrity management program are qualified for their assigned responsibilities. [§192.911(l) & §192.915 & ASME B31.8S, §12(b)(4)]

a. **[PI]** Verify that the Integrity Management Program requires supervisory personnel to have the appropriate training or experience for their assigned responsibilities. [§192.915(a)]

b. **[PI]** Verify the qualification of personnel that carry out assessments and who evaluate assessment results. [§192.915(b)]

c. **[PI]** Verify the qualification of personnel who participate in implementing preventive and mitigative measures including: [§192.915(c)]

i. Personnel who mark and locate buried structures.
ii. Personnel who directly supervise excavation work.
iii. Other personnel who participate in implementing preventive and mitigative measures as appropriate. [ASME B31.8S, §12(b)(4)]

d. **[PI]** Verify that the personnel who execute the activities within the integrity management program are competent and properly trained in accordance with the quality control plan. [ASME B31.8S,§11(a)(8) & §12.2(b)(4)]

L.3 Invoking Non-Mandatory Statements in Standards Verify that non-mandatory requirements (e.g., "should" statements) from industry standards or other documents invoked by Subpart O (e.g., ASME B31.8S-2001 and NACE RP0502-2002) are addressed by one of the following approaches: [§192.7(a)]

a. **[P]** Incorporated into the operator’s plan and implemented as recommended in the standard; or

b. **[P]** An equivalent alternative method for accomplishing the same objective is justified and implemented; or

c. **[P]** A documented justification is included in the plan that demonstrates the technical basis for not implementing recommendations from standards or other documents invoked by Subpart O.

M. Communications Plan

M.1 External and Internal Communication Requirements Verify that an integrity management communication plan exists that meets the requirements of ASME/ANSI B31.8S, Section 10. [§192.911(m)]

a. **[PI]** Verify provisions for external communications exist for the following: [ASME/ANSI B31.8S, §§10.1 & 10.2]

i. Landowners and tenants along the rights-of-way.
ii. Public officials other than emergency responders.
iii. Local and regional emergency responders.
iv. General public.

b. **[PI]** Verify provisions for operator internal organizational communication exist to establish understanding of and support for the integrity management program. [ASME/ANSI B31.8S, §10.3]

M.2 Addressing Safety Concerns Verify that provisions exist to address safety concerns raised by:

a. **[PI]** OPS and State or local pipeline safety authorities, as applicable. [§192.911(m)(1) and §192.911(m)(2)].

N. Submittal of Program Documents

N.1 Integrity Management Program Document Submittal Verify that the operator includes provisions in its program to submit, upon request, the operator's risk analysis or integrity management program to: [§192.911(n)]

a. **[PI]** OPS and State or local pipeline safety authorities, as applicable. [§192.911(n)]