TR 22-66 – Integrity Management

TR Number	**22-66**
Primary	192.917
Purpose	Review and develop GM as appropriate in light of Amendment 192-132; and Amendment 192-125 (from TR 19-59).
Origin/Rationale	Amendment 192-132; Amdt. 192-125 (from TR 19-59)
Notes	Potential Threats to Pipeline Integrity; added TR 19-59 to scope.
Assigned to	IM/Corr TG

Note: *Revisions are shown in yellow highlight and red font.*

Section 192.917

~~*This guide material is under review following Amendment 192-132.*~~

Note: References to ASME B31.8S throughout this section of guide material are specific to the edition of ASME B31.8S as incorporated by reference (IBR) in §192.7. Section 192.917(b) requires that the operator comply with the IBR edition of ASME B31.8S, Appendix A even though Appendix A is titled as "nonmandatory." See 3.2 of the guide material under §192.907.

1 GENERAL

(a) Threats are analyzed to determine which threats may contribute to the failure of a pipe segment, which assessment techniques are appropriate, and which preventative and mitigative measures should be implemented. Threat analysis requires data integration and allows for the prioritization of both assessments and mitigation measures (§192.917(b)). Operators should develop processes to ensure information acquired about both covered and non-covered segments is considered in determining risk and appropriate preventative and mitigative measures.

(b) Section 192.917(b) requires that operators ~~must~~ gather and integrate data relevant to the entire pipeline that could be relevant to the covered segment. Pipeline attributes to be collected and integrated are defined in §192.917(b)(1). ~~using a prescriptive-based program consider the i~~Information within ASME B31.8S, Appendix A might also be helpful when collecting this data. ~~When gathering data to meet ASME B31.8S, Appendix A, if the operator is missing data, conservative assumptions should be used and documented. Operators using a performance-based program must meet or exceed the prescriptive-based program data requirements per §192.913(b).~~

(c) When using an SME input in the threat and risk process, the operator must have processes in place to maintain accuracy and consistency of information. At a minimum, SME risk inputs must be approved for use and the approver's name and qualifications be documented (§192.917(b)(2)).

(1) Operators can implement a variety of control measures (e.g., training, qualification requirements, use of independent technical expertise) to ensure quality of the processes.

(2) These control measures should be documented in the written IMP plan.

(d) Validated data is the preferred input where possible. Data acquired from routine O&M activities should be quality checked through other operator processes. Data from material verification (§192.607) or MAOP validation (§192.624) may be used to evaluate threats.

(e) Information should be mapped using available tools to facilitate the identification of spatial relationships of overlapping data and interactive threats (e.g., corrosion, encroachments, line crossings, shared rights-of-way, pipeline damage, overhead lines).

(f) The interrelationships between threats and their underlying risk factors must be considered as they have the potential to affect outcomes (§192.917(b)(4)).

(g~~c~~) An operator must consider ~~all~~ potential threats per ~~ASME B31.8S in its IMP~~ ~~(~~§192.917(a)~~)~~. If the operator is missing data, conservative assumptions should be used and documented in the risk analysis.

(h~~d~~) ~~An operator~~ A threat may be active or inactive for a specific risk assessment cycle; however, threats to a pipeline can ~~may~~ change (e.g., weather or other outside forces, acquisition of new data, preventative and mitigative measures such as pipe replacement). The operator's IMP should include provisions for re-analysis of the threat categories periodically to determine status changes. The severity of events affecting threats should be considered to determine the review frequency.

(i~~e~~) An operator should continually monitor operations and maintenance (O&M) and other activities, integrating relevant information during a threat analysis that might indicate a change in the status of a threat. Communication between O&M and integrity personnel is a key component to evaluating threats.

(j~~f~~) In the following guide material, Sections 2 through 11 deal with threats to steel transmission pipelines. Section 12 deals with threats to plastic transmission pipelines. Section 13 addresses crack and crack-like defects, Section 14 addresses data integration, Section 1~~4~~5 addresses threat status, Section 1~~5~~6 addresses risk assessment, and Section 1~~6~~7 provides a list of references.

2 IDENTIFICATION OF THREATS TO STEEL PIPELINES

Section 192.917(a) requires operators to address potential threats to pipeline integrity. See 1~~6~~7.1.1 below for reference containing a representative list of pipeline threats that includes examples and comments. Threats for steel pipelines are commonly grouped into the following categories.

(a) Time-dependent.
(b) Stable.
(c) Time-independent.
(d) ~~Other~~ Human error.

2.1 *Time-dependent threats.*

Note that this guide material follows threat categories as listed in §192.917; ASME-B31.8S category groups may differ, but individual threats should be considered.

Time-dependent threats are those that may grow more severe over time, such as corrosion. Analysis based on sound engineering practices may be used to help predict when these threats might become critical. Corrosion threats include the following.

(a) External corrosion.
(b) Internal corrosion.
(c) Stress corrosion cracking.

2.2 *Stable threats.* ...

2.3 *Time-independent threats.*

Time-independent threats are generally associated with events that may take place along the pipeline segment and can happen at any time. These threats include the following.

(a) Excavation damage (including previous damage).
~~(b) Incorrect operations (includes human error).~~
(b~~c~~) Weather-related and outside force.
(c) Vandalism.
(d) Other third-party damage.

~~Note that §192.917 identifies "Human Error" as a fourth threat category. This guide material follows the ASME B31.8S threat categories and addresses the human error threat in conjunction with the incorrect operations threat.~~

2.4 *Human error.~~Other threats.~~*

(a) Operation and maintenance.
(b) Design and construction.

~~Section 192.917(a) requires operators to analyze the pipeline for other threats that may not fit into one of the above categories.~~

3 EXTERNAL CORROSION

In evaluating the threat of external corrosion, §192.917(b)(1) and ASME B31.8S, Appendix A1 provides a list of data that the operator is required to gather and evaluate. This threat applies to both belowground and aboveground installations.

3.1 *Year of installation.*

Since the threat is time dependent, the threat may increase the longer the pipe is in service. If the installation year is not known, conservative estimates should be used.

3.2 *Coating type and application method.*

While coated pipe is generally less susceptible to external corrosion, all coatings are not equally effective. The coating application method should also be considered when determining the existence and severity of the external corrosion threat. For example, a field-applied coating may not have the same performance as a mill-applied coating of the same type. Bare pipe may be considered as a coating type of "none."

The quality and compatibility of girth weld coatings ~~need to~~ should be evaluated. Coating inspection repairs and reports should be considered, including tests for coating continuity performed at the time of installation or repair (e.g., holiday inspection, jeeping).

3.3 *Coating condition.*

The following should be considered in evaluating the coating condition.

(a) Findings from prior assessments.
(b) Data from close-interval survey (CIS), electrical survey, and coating surveys, including DCVG or ACVG.
(c) Data from pipeline inspection reports
(d) Leak data.
(e) Data from atmospheric corrosion reports.
(f) Changes in cathodic protection current levels.
(g) Evaluation of coating under insulation.
(h) Post-backfill coating surveys.
(i) Data gathered through integrity assessments or direct evaluation of the pipe coating.

3.4 *Cathodic protection.*

Cathodic protection (CP) can greatly reduce the potential for external corrosion on buried facilities. The following should be considered.

(a) Years that the pipeline operated before CP was installed.
(b) Type of CP system (i.e., galvanic, impressed current, or none), and location.
(c) Dates of major CP changes including lengthy outages of CP devices (e.g., additional rectifiers and ground beds installed, AC mitigation systems).
(d) Effectiveness of the CP system (e.g., adequacy of pipe-to-soil readings, electrical isolation is performing as designed, external corrosion coupons).
(e) Rectifier inspection and remote monitoring records to determine if the segment has had any significant changes in protective current requirements.
(f) Results of interference surveys such as AC, DC, or foreign structure interference.
(g) Studies required by §192.465(f).

(h) Remedial actions and documented results.

3.5 *Soil and backfill characteristics.*

Typical soil characteristics that may influence the threat of external corrosion include the following.

(a) Soil resistivity.
(b) Soil pH.
(c) The existence of certain bacteria.
(d) Soil types (e.g., sand, clay). See United States Department of Agriculture's (USDA) Soil Survey Data to obtain mapped soil types if unknown (websoilsurvey.sc.egov.usda.gov/App/WebSoilSurvey.aspx).
(e) Type of backfill or padding, if known.

See 17~~6~~.1.2 below for a reference on soil characteristics and corrosion, and 17.1.3 below for a reference on the USDA Web Soil Survey.

3.6 *Pipe inspection reports.*

Pipe inspection reports provide documentation that external corrosion existed or did not exist on buried piping at the excavation site. The report may also provide data on the following.

(a) Coating type and condition.
...
(g) Root cause of external corrosion.
(h) ~~Non-destructive~~ Nondestructive testing results.
(i) Repairs.

Atmospheric corrosion inspection reports may provide information similar to (a), (e), and (f).

3.7 *History of microbiologically influenced corrosion (MIC).* ...

3.8 *External corrosion leak history.* ...

3.9 *Wall thickness.* ...

3.10 *Pipe diameter.* ...

3.11 *Operating stress level.*

Operating stress level is a key factor in predicting failure mechanisms and determining the tolerance to external corrosion. Flow reversal might change the pressure gradient of a pipeline by affecting the operating stress level at different points along the pipeline. The effect of new pressure gradient on existing defects should be evaluated. See OPS ADB-2014-04 (79 FR 56121, Sept. 18, 2014; reference Guide Material Appendix G-192-1, Section 2) for additional evaluation guidance on flow reversals.

3.12 *Prior assessments.*

Evaluating the findings from prior assessments (e.g., in-line inspection, external corrosion direct assessment) and resulting remedial actions can provide useful data in determining the threat of external corrosion. Pressure test failures might provide or point to additional information regarding pipe condition. Consider results from both covered and non-covered segments in evaluating external corrosion threats for other pipeline segments with similar coating and environmental characteristics.

3.13 *Crossings and casings.*

(a) Location of foreign line crossings and associated bonds (e.g., critical, non-critical).
(b) Proximity of nearby high voltage power lines, particularly where distances from pipeline centerline deviate.
(c) Proximity of other AC or DC inducing features (e.g., transit systems, underground mines, foreign CP groundbeds).
(d) Location and status of cased crossings (e.g., type of short, filled or unfilled annulus).

3.14 External corrosion monitoring.

Location, type, and results from any external corrosion monitoring. These may include permanent or temporary mounted recording devices or field measurements. Corrosion monitoring may be installed for either general corrosion or specific to a particular localized threat such as AC corrosion.

3.15~~3~~ Other considerations.

In addition to the data elements listed in §192.917(b)(1) ~~ASME B31.8S, Appendix A1~~, the following ~~data~~ may be useful in evaluating external corrosion.

(a) Electrical shorts (e.g., ~~casings,~~ other metallic structures).
(b) Stray current.
~~(c) Interference bonds.~~
(~~d~~ c) Electrical current mitigation devices.
(~~e~~ d) Areas previously identified as active corrosion areas.
(~~f~~ e) Areas where electrical surveys are impractical (e.g., bare pipe, ineffectively coated pipe). See guide material under §192.465.
(~~g~~ f) Selective seam corrosion (sometimes referred to as preferential seam corrosion) is corrosion across or adjacent to longitudinal seams and is most prevalent in electric-resistance-welded (ERW) pipe.
(~~h~~ g) Incident and safety-related condition reports related to external corrosion.
(h) Coating compatibility with pipe wall temperature range.
(i) Known issues with legacy pipe.

4 INTERNAL CORROSION

In evaluating the threat of internal corrosion, §192.917(b)(1) ~~ASME B31.8S, Appendix A2~~ provides a list of data that the operator is required to gather and evaluate. Although the operator is required to collect the following data, covered segments may not be susceptible to the threat of internal corrosion if any pipeline inclination angle greater than a critical angle exists upstream of the covered segment. For guidance in determining the critical angle and the pipeline inclination angle, see 5.1, 5.2, and 5.3 of the guide material under §192.927.

4.1 Year of installation. ...

4.2 Pipe inspection reports.

Internal pipe inspection reports provide documentation regarding the presence of internal corrosion. The location of the internal corrosion may indicate the mechanism of corrosion (pits at the top of the pipe indicate a more vapor driven mechanism caused by high dew points that allow condensation of water, while pitting along the bottom of the pipe indicates the presence of liquid water; see guide material under §192.476). Changes in pipe direction may be prone to erosion corrosion. See 1~~6~~7.1.~~3~~4 below.

4.3 Internal corrosion leak history.

Leak history, trends, and leak locations are factors in determining the susceptibility of the internal corrosion threat and may provide information regarding low spots or liquid hold-up locations, and the presence of internal corrosion on longitudinal seams. Flow reversals, bidirectional flow, or flow history might inform ~~alter future~~ internal corrosion evaluations and assessments on pipelines due to ~~potentially~~ potential new ~~liquid hold-up~~ locations of liquid accumulation.

4.4 Wall thickness. ...

4.5 Pipe diameter. ...

4.6 Prior assessments.

Evaluating the findings from prior assessments (e.g., in-line inspection, ~~pressure tests,~~ internal corrosion direct assessment) and resulting remedial actions can provide useful data in determining the threat of internal corrosion. Unsuccessful pressure tests might provide additional information regarding pipe condition.

The risk of internal corrosion could increase after hydrostatic testing due to the following.

(a) Water or debris left in the pipeline after hydrostatic testing.
(b) The test water contains bacteria that promote MIC.

4.7 Gas, liquid, and solid sampling analysis.

Analysis of gas, liquid, and solid samples can be used to help determine the probability of internal corrosion and help identify the cause of corrosion. Data should be ~~trended to determine if values are increasing or decreasing~~ analyzed for indications of changes to the threat of internal corrosion. See §~~§~~ 192.477 ~~and 192.478~~ for monitoring requirements and guide material under §192.475. Further reference materials are in 17 below.

[LB note: Proposed reference to 192.478 in above GM is removed per court ruling vacating 192.478 (Amendment 192-138 was subsequently issued on 1/15/2025 and removes §192.478) and the subsequent removal of proposed GM under 192.478 in TR 19-22. Below GM is now proposed to be included in GM under 192.475 instead of 192.478 in TR 19-22. See TR 19-22.]

~~(a) Gas. When analyzing for internal corrosion, partial pressures (see 4.10 below) and gas chemistry are important considerations. Typical gas analysis should include the determination of the following constituents.~~

~~(1) *Carbon dioxide (CO_2).* CO_2 in the gas can mix with water in the gas stream to form carbonic acid, which is corrosive to steel. The percentage of CO_2 in the gas stream can be determined by using a stain tube or analyzing the sample by gas chromatography. CO_2 partial pressure below 3 psia is generally considered non-corrosive. See 167.1.45 and 167.1.56 below. The table below identifies typical concern levels for CO_2 partial pressures.~~

~~**CO_2 Partial Pressure (psia)**~~	~~**Level of Concern**~~
~~< 3~~	~~Low Risk~~
~~3 – 30~~	~~Moderate Risk~~
~~> 30~~	~~High Risk~~

~~**TABLE 192.917i**~~

~~(2) *Hydrogen sulfide (H_2S).*~~

~~(i) H_2S may be a normal constituent in natural gas, and can also be formed due to MIC. H_2S will combine with water to form a weak sulfuric acid which is corrosive to steel. The presence of H_2S may also cause hydrogen blistering and sulfide stress cracking.~~

~~(ii) The amount of H_2S in the gas stream may be determined by using a stain tube or an electronic meter. The stain tube typically provides a read out in ppm which, if necessary, is then converted to percentage. Electronic meters give a direct reading of the percent of H_2S in the gas.~~

~~(iii) A typical operator-set tariff range for H_2S is between 4 and 16 ppm. Gas maintained at tariff quality is considered a low concern for internal corrosion caused by H_2S.~~

~~(3) *Oxygen (O_2).* O_2 is often present in small amounts in natural gas and, when present in a gas stream containing water, oxygen can act as a catalyst to speed up general and pitting corrosion. O_2 can be measured with a stain tube or by gas chromatography. If O_2 is indicated, the dissolved O_2 concentration in water should be calculated. A dissolved O_2 concentration above 10 to 50 ppm is considered corrosive to steel pipelines.~~

~~(4) *Water content or dew point.* For corrosion to occur there must be an electrolyte, such as water, present to react with the gas constituents. High dew points may allow water to condense at certain locations and activate corrosion mechanisms. Water content in the gas stream can be measured with either a stain tube or an electronic meter. Both devices determine the amount of water in pounds per million cubic feet (lbs/MMSCF) of the gas. Dry~~

~~gas is defined in §192.3. A value of less than 7 lbs/MMSCF is generally considered non-corrosive. At higher concentrations and certain pressure and temperature conditions, it is possible for water vapor to condense.~~

~~(b) Liquid. For evaluating internal corrosion, only liquids containing electrolytes need to be analyzed. Non-electrolytes, such as drip gas and other hydrocarbons, may not need to be analyzed because they do not contribute to corrosion. Water indicators are available to determine if the sample contains electrolytes. When analyzing for internal corrosion, a typical liquid analysis includes the following.~~

~~(1) *pH.* The pH measures the acidity or alkalinity. A pH of 7 is neutral. A reading of less than 7 is acidic, with lower numbers indicating a stronger acid. Readings above 7 are alkaline, with higher numbers indicating a stronger base. Readings near neutral represent less corrosive liquids. Low pH levels, such as 5.0 or less, may result in increased corrosion.~~

~~(2) *Iron or manganese.*~~

~~(i) Iron might exist naturally in liquids in small amounts. Manganese is not normally present in liquids produced from natural gas sources, but is present in steel.~~

~~(ii) Iron concentrations above 2500 ppm or manganese concentrations above 25 ppm may indicate corrosion of steel. A manganese to iron ratio between 1:50 and 1:200 may indicate the source of iron is from corrosion. Deviations from this ratio range could indicate the presence of other material or other chemical mechanisms. See 167.1.67 below.~~

~~(iii) Due to precipitation of iron from the liquid sample, a lower iron concentration in solution may not indicate a reduced rate of corrosion. Proper handling of samples should be ensured to prevent precipitation.~~

~~(iv) When analyzing iron and manganese counts, the system parameters (e.g., flow rate, amount of water, temperature) should be reviewed and scaling tendency should be determined.~~

~~(3) *Salt or chlorides.* Salt, or more specifically chloride, is not in itself corrosive. Water containing chlorides or other salts tend to be more corrosive than fresh water. The type and concentration of anions in the sample can be used to predict acceleration of corrosion activity (e.g., when chloride ions are present) or inhibition of corrosion activity.~~

~~(c) Solids. Solids should be sampled whenever they are found inside the pipe. Bacteria cultures (see 4.8 below) and pH need to be taken immediately upon exposing the solids, because the values may change when exposed to air. A typical solid analysis includes the following.~~

~~(1) *Iron sulfide (FeS_2).* Iron sulfide is a byproduct of the reaction of H_2S and steel, and is also produced by sulfate reducing bacteria. It may be identified as the minerals pyrite or marcasite. Iron sulfide often coats the internal surface of pipe, but because iron sulfide is cathodic to steel, breaks in the scale may often cause acceleration of pitting, It may commonly be found as black dust inside of pipelines.~~

~~(2) *Mineral scale.* Mineral scale may contain a variety of components and compounds, depending on the contaminants and environment. Scale should be examined to determine actual composition, which may suggest corrosion mechanisms. Mineral scale might include salt, calcium and other carbonates (CO_3), sulfide minerals, as well as a variety of iron minerals. Iron found in a solid sample that has accumulated in vessels, loosened during cleaning pig runs, or debris found when a cutout is made on the line typically represents corrosion product. When evaluating for iron, manganese should also be evaluated.~~

~~(3) *Erosive material.* Material and other debris, such as sand, quartz, and black powder, might be present in pipeline solids and may create erosion corrosion issues.~~

~~*4.8 Bacteria culture tests.*~~

~~Liquids and solids collected should be tested for the presence of both acid-producing bacteria (APB) and sulfate-reducing bacteria (SRB) through the use of culture tests. The presence of bacteria in the system does not necessarily indicate that MIC is occurring. However, further investigation needs to be performed.~~

~~*4.9 Internal probes or coupons.*~~

~~Internal probes or corrosion coupons may be used to indicate the presence of internal corrosion. These weight loss devices provide an indication of the corrosion rate in mils per year.~~

4.8~~10~~ Operating parameters.

Operating parameters include the following.

(a) Temperature. The temperature of the gas or liquid present in the pipeline will affect the corrosion rate. In general, each 18 °F temperature increase will double reaction rates. The temperature of both the gas and liquid phases are important. In addition, locations that cool the gas (e.g., crossings of streams, rivers, and swamps) or changes in flow or pressure may cause a condensation of liquids. The temperature of production or storage gas might be higher closer to a well.

(b) Flow rates. Low flow rates may not effectively sweep the pipeline of liquids or other debris. Flow rates should be considered where there are changes in pipe diameters, low spots, or other potential liquid collection locations along the pipeline.

(c) Flow direction. Bidirectional flow, flow history, or flow reversal ~~may impact~~ might affect the location and the rate of internal corrosion.

(d) Changes in source of natural gas. Source and location changes of natural gas entering a transmission line might change the composition of the gas stream.

(e) Pressure. The operating pressure is used to calculate partial pressures for the constituents. The partial pressure of a constituent ~~determined in 4.7~~ is dependent on the amount of the constituent and the operating pressure of the pipeline. The partial pressure of a gas is calculated by multiplying the mole fraction of the component by the pipeline pressure converted to absolute pressure (psia).

For example, if the mole fraction of CO_2 is 1.2% and the operating pressure of the pipeline is 200 psig (214.7 psia), the partial pressure is 0.012 x 214.7 psia = 2.6 psia, and CO_2 is not likely to cause corrosion. If the operating pressure is 2000 psig (2014.7 psia), the same CO2 percent would yield a partial pressure of 24.2 psia (0.012 x 2014.7 psia = 24.2 psia), which is more likely to cause internal corrosion.

4.9~~11~~ Operating stress level.

Operating stress level is a key factor in predicting failure mechanisms and determining the tolerance to internal corrosion. Flow reversals might change the pressure gradient of a pipeline by affecting the operating stress level at different points along the pipeline. The effect of new pressure gradient on existing defects should be evaluated. See OPS ADB-2014-04 (79 FR 56121, Sept. 18, 2014; reference Guide Material Appendix G-192-1, Section 2) for additional guidance on flow reversals.

4.10~~12~~ Other considerations.

In addition to the data elements listed in §192.917(b)(1) and ASME B31.8S, Appendix A2, the following data may be useful in evaluating corrosion.

(a) ...

...

5 STRESS CORROSION CRACKING

(a) In evaluating the threat of stress corrosion cracking (SCC), §192.917(b)(1) and ASME B31.8S, Appendix A3 provides a list of data that the operator is required to gather and evaluate. Additional information can also be found in guide material under §192.613, and the reference listed in 1~~6~~7.1.~~7~~8 below. Pipeline segments may be susceptible to two types of SCC; high pH and near-neutral pH.

(b) ...

...

5.1 Age of pipe. ...

5.2 *Operating stress level (percent SMYS).*

A pipeline operating above 60% SMYS might be susceptible to high pH SCC. Increases in steel toughness, which have generally occurred in parallel with increasing SMYS, have significantly increased the size of cracks that a pipeline can tolerate without failing. With improved manufacturing procedures, higher-strength grades of line pipe are available for which the combination of diameter and MAOP, or maximum actual operating pressure (MOP), may minimize the effects of SCC. See 1~~6~~7.1.~~8~~9 below.

5.3 *Operating temperature* ...

5.4 *Distance of the segment from a compressor station.*

A pipeline segment less than 20 miles downstream of a compressor station may be more susceptible to high pH SCC because of high discharge temperatures. The potential for SCC should be considered when modifying existing suction and discharge piping of a compressor station for flow reversal. Historical compressor locations should also be considered.

5.5 *Coating type.*

(a) SCC has not been found on pipe with undamaged FBE or extruded polyethylene coating. High pH SCC has been found under disbonded coal tar, asphalt, and tape coatings. Near-neutral pH SCC is most commonly associated with tape coatings, but has also been found under asphalt coatings. It has been reported that about three-quarters of near-neutral pH SCC-related occurrences are associated with these tape coatings. See 1~~6~~7.1.~~8~~9 below.

(b) ...

(c) ...

5.6 *History of SCC.*

There is a high probability of finding additional SCC in areas where it has previously been found. An operator may have a unique factor such as pipe manufacturer or age of the pipe that is also important in the determination of the potential severity and location of the threat.

The operator needs to evaluate results from previous assessments, stress corrosion cracking evaluations, and other findings (§192.917(b)(1)(xxiv)(H)).

5.7 *Other considerations.*

(a) Soil types. Particularly high resistance soils might be correlated with near-neutral pH SCC. See 1~~6~~7.1.~~7~~8 below.

...

(e) Cyclic fatigue. A pipeline that is exposed to cyclic pressure fluctuations might experience cyclic softening. Cyclic softening is a phenomenon in which the application of stress cycles close to maximum stress levels (below the yield stress) manifests itself as a loss of yield strength. The operator has little control over the metallurgical susceptibility to cyclic softening but can, in some instances, monitor the magnitude and frequency of pressure cycles on a pipeline. See 1~~6~~7.1.~~8~~9 below.

6 MANUFACTURING THREATS

(a) This threat refers to defects of the pipe seam or pipe body that are associated with the manufacturing process.

(b) Some examples of manufacturing defects include the following.

(1) Seam defects.

(i) Low quality seams associated with early manufacturing processes, including flash-welded seams, pipe with a longitudinal joint factor <1 (see §192.113), and ERW process, particularly ~~very~~ early ERW processes (e.g., pre-1970 ERW pipe).

(ii) Incomplete fusion (incomplete coalescence of portions of the metal in a weld joint).

(iii) Hook cracks (upturned fiber imperfections caused by imperfections at the edge of the skelp).

(2) ...

(3) Ovality (oval or egg-shaped ~~pipe~~ cross-sections).
(4) ...
...
(9) ...

(c) In evaluating manufacturing threats, §192.917(b)(1) and ASME B31.8S, Appendix A4 provides a list of data the operator is required to gather and evaluate as outlined below.

6.1 Pipe material.

Impurities in the steel can lead to laminations and inclusions. Pipe or materials not manufactured to an established standard or if the standard is unknown.

6.2 Year of installation. ...

6.3 Manufacturing process.
(a) Seamless.
(b Welded.
(c) Specification to which it was manufactured.
(d) Pipe with actual yield strength below specified minimum yield strength. See 1~~6~~7.1.~~9~~10 and 1~~6~~7.1.~~13~~14 below.

6.4 Seam type.
(a) ...
...
(d) Section 192.917(e)(4) specifically addresses pipelines that are made by the low-frequency ERW, lap welded pipe, and pipe with longitudinal joint factors < 1 ~~manufacturing process~~ because of historical incidents. ERW ~~This type of~~ manufactured pipe is susceptible to selective seam corrosion. ~~If the operator has a known history of seam failures, this manufacturing threat must be considered to exist. See 167.1.1112, 167.1.1213, and 167.1.1314 below.~~
(e) Pipe must be prioritized as a high-risk segment if it meets the conditions as outlined in ASME B31.8S Appendix A4.3 and A4.4 and:
  (1) Has experienced a seam failure, or
  (2) Had an operating pressure increase during the preceding 5 years. Operating pressure increase may include abnormal operations (§192.605(c)) or MAOP excursions (§191.23(a)(10)).
(f) If the operator has a known history of seam failures, this manufacturing threat must be considered to exist. See 17.1.12, 17.1.13, and 17.1.14 below.
(eg) The operator could identify seam or pipe defects during normal operation and maintenance activities, such as leak repairs, failure analyses, and prior assessment results.

~~*6.5 Joint factor.*~~
~~ASME B31.8S, Appendix A4.3 requires that if pipe has a joint factor of less than 1.0 (see table in §192.113), then a manufacturing threat is considered to exist.~~

6.~~5~~6 ~~Operating pressure history~~ Threat stability.
(a) An operator may consider a manufacturing threat stable only if the covered segment:
  (1) Has been subjected to a Subpart J test to at least 1.25 times MAOP, and
  (2) Has not experienced a reportable incident due to a manufacturing or construction defect since the date of the most recent Subpart J test. A successful Subpart J test may be an assessment as allowed by §192.921 or MAOP reconfirmation (§192.624).

  Note: Non-Subpart J tests or pressure tests to less than 1.25 times MAOP do not meet current requirements to consider the manufacturing threat stable.
(b) A segment must be considered high risk if any of the following events have occurred (§192.917(e)(3)).
  (1) A reportable incident due to manufacturing-related defect:
    (i) Construction,
    (ii) Installation, or
    (iii) Fabrication-related defect.
  (2) MAOP increases.
  (3) Stresses leading to cyclic fatigue increase.

(c) If an operator experiences or has experienced MAOP excursion (§191.23(a)(10)) since the pressure test, the operator should reconsider the stability of the threat.

~~For the covered segments, the operator must collect pressure history for at least the past five years to document at which pressure the defects are considered stable (see §192.917(e)(3)). Also, see 12.3(b)(4) below. Manufacturing and construction defects are considered to be stable defects if the operating conditions did not significantly change in the five years prior to the identification of the HCA.~~

~~Operation of a pipeline without failures demonstrates that the manufacturing defects are stable and have not been a threat to pipeline integrity. Changes in operating conditions, such as a significant increase in pressure, could cause latent defects to grow. For changes in pipeline operating conditions, where operating pressure will be above the historic operating pressure or if stresses that could lead to cyclic fatigue increase, the operator must assign a high priority to assessing the manufacturing threat (§192.917(e)(2) and (3)).~~

6.6~~7~~ Other considerations.

Manufacturing threats may be magnified due to local environmental conditions. An operator is required to examine the terrain and right-of-way for subsidence, landslides, washouts, frost heaving, or other lack of support if any of the following conditions exists (§192.917(e)(4)).

(a) Pipe is more than 50 years old.
(b) Pipeline is mechanically coupled.
(c) Pipeline is joined by oxyacetylene girth welds.
(d) For additional guidance for evaluating manufacturing defects, see 17.1.15 below.

~~Indications are that a successful hydrotest at 1.25 times the MOP might prove the stability of manufacturing defects. See 16.1.14 below.~~

7 CONSTRUCTION THREATS

Construction threats are related to the fabrication process used in the construction of a facility. Construction threats include the following.

(a) ...
...
(i) ...

In evaluating construction threats, §192.917(b)(1) and ASME B31.8S, Appendix A5 provides a list of data that the operator is required to gather and evaluate.

7.1 Pipe material. ...

...

7.12 Bend radii and angle for wrinkle bends.

Review construction and repair records for locations and design parameters of wrinkle bends. See 1~~6~~7.1.~~15~~16 below.

7.13 Operating pressure history and expected operation including significant pressure cycling and fatigue mechanisms.

Review operating records for history of significant pressure cycling or pressure increases over a historic MAOP ~~before HCA identification~~ for the consideration of the construction threat.

(a) An operator may consider a construction threat stable only if the covered segment:
  (1) Has been subjected to a Subpart J test to at least 1.25 times MAOP, and
  (2) Has not experienced a reportable incident due to a manufacturing or construction defect since the date of the most recent Subpart J test. A successful Subpart J test may be an assessment as allowed by §192.921 or MAOP reconfirmation (§192.624).

  Note: Non-Subpart J tests or pressure tests to less than 1.25 times MAOP do not meet current requirements to consider the construction threat stable.

(b) A reportable incident due to manufacturing-related defect, construction, installation, or fabrication-related defect, MAOP increases, or stresses leading to cyclic fatigue increase, a segment must be considered high risk if any of the following events have occurred (§192.917(e)(3)). If an operator experiences or has experienced MAOP excursion

(§191.23(a)(10)) since the pressure test, the operator should reconsider the stability of the threat.

7.14 Other considerations.
In addition to the data elements listed in §192.917(b)(1) and ASME B31.8S, Appendix A5, the following data may be useful in evaluating for construction threats.
(a) ...
...
(j) Aerial crossings (e.g., spans, bridge crossings).
(k) Aboveground facilities.
(l) Field-applied coatings.
(m) Locations and design parameters of miter bends.
(n) Coating surveys, inspections, and disbondment repairs (e.g., jeeping, holidays).
(o) Results of §§ 192.624, 192.632, and 192.607.

Construction defects are much more susceptible to longitudinal stresses than to hoop stresses. See 1~~6~~7.1.~~14~~15 below.

8 EQUIPMENT THREATS

Equipment can be defined as pipeline facilities other than pipe and pipe fittings and includes the following.
(a) ...
...
(g) ...

In evaluating equipment threats, §192.917(b)(1) and ASME B31.8S, Appendix A6 provides a list of data that the operator is required to gather and evaluate.

8.1 Year of installation of failed equipment. ...

...

9 THIRD-PARTY DAMAGE

...

In evaluating the threat of third-party damage, §192.917(b)(1) and ASME B31.8S, Appendix A7 provides a list of data that the operator is required to gather and evaluate. All facilities are subject to the threat of third-party damage.

9.1 Vandalism incidents. ...
...
9.6 One-call records.
...
(c) Effectiveness of one-call program. See 1~~6~~7.3.1 below.

9.7 Encroachment records.
...
9.8 Other considerations.
...
(c) Current d~~D~~epth of cover.
(d) Abnormal operations, safety-related conditions, security threats, or alarms.

10 ~~INCORRECT OPERATIONS (~~HUMAN ERROR~~)~~ (FORMERLY INCORRECT OPERATIONS)

This threat is time-independent and may occur at any time. Human error often results in incorrect operations such as operational or maintenance mishaps. ~~Incorrect operations~~ Human errors include the following.

...

(d) Use of uncalibrated or unauthorized tools.

In evaluating the threat of incorrect operations, §192.917(b)(1) and ASME B31.8S, Appendix A8 provides a list of data that the operator is required to gather and evaluate. All facilities are subject to the threat of incorrect operations.

10.1 Procedure review information.

The procedure review, and documentation, for completeness and effectiveness should include the following.

...

(h) Operator procedures for conducting post-incident, post-emergency, abnormal operations, and failure investigations.

(i) Control room management program.

10.2 Audit information.

The results of both internal and external audits should be reviewed. Internal audits might include self audits in the following areas.

(a) ...

(b) Construction activities.

(c) Office operations (e.g., incorrect, incomplete documentation~~, processes~~).

(d) Mapping.

10.3 Failures caused by incorrect operations.

...

11 WEATHER AND OUTSIDE FORCES

Weather-related and outside force threats have the capability to create extreme loading conditions on pipelines. Section 192.917(a)(3) and ASME B31.8S, Appendix A9 require operators to consider seismicity, geology, and the soil stability of the area surrounding pipelines, and ~~In assessing this type of threat, ASME B31.8S, Appendix A9~~ provides a list of data that the operator is required to gather and evaluate to determine whether pipelines are being subjected to extreme loading conditions caused by weather or outside forces. Aboveground facilities are also prone to weather-related events.

11.1 Pipe joining method.

...

11.2 Geology~~Topography~~, soil conditions, and other geohazards ~~frost depth~~.

~~The following topographical areas~~ Pipelines susceptible to threats from the following geohazards should be analyzed ~~examined~~ to determine if they might undergo ~~contribute to this threat by exerting~~ extreme loading conditions (e.g., bending, tension, compression). Operators should consider the ~~impact~~ effect that cascading hazards will have on extreme loading conditions as well as interactive geohazard threats. See 6 of guide material under §192.613 for additional information on cascading hazards.

(a) Slopes ~~prone~~ or unstable ground ~~to movement or other unstable areas~~ that would induce additional stress ~~in~~ on a pipeline due to the movement of soil (e.g., creep, downslope material movement). Downslope material movement includes slides, flows, rock falls, and rock topples.

(b) Areas prone to recurrent or intermittent flooding that causes surface erosion, saturated soils, or increased buoyant forces on pipelines. See guide material under §192.317 for information regarding protection from flooding. ~~Extremely saturated soils that produce buoyant forces on pipelines.~~

(1) River and stream crossings.
(2) Lowlands including floodplains, wetlands, and swamps.
(3) Coastal areas prone to tidal surges from hurricanes or tropical storms.
(4) Frequency of flooding events.

(c) Areas and materials (e.g., soil, bedrock) susceptible to frost heave and freeze-thaw cycles.

(d) Soils that undergo recurrent or cyclical shrink and swell processes ~~Highly expansive or unstable soils~~ (e.g., some clays ~~or~~, manmade soils).

(e) Other ~~l~~locations with known geologic conditions that contribute to instability (e.g., karst topography, sinkholes, underground mining or mine subsidence, ~~other~~ regional subsidence ~~areas~~).

11.3 Fault zones.

The following should be considered in evaluating an active or known fault zone.

(a) ~~Location of earthquake fault lines.~~ A fault line is considered active if movement has been observed or evidence exists of seismic activity (earthquakes) during the last 10,000 years. For the purposes of pipeline seismic evaluations, active fault lines within approximately 60 miles (100 km) of the pipeline should be considered in the evaluation. The operator should evaluate if a larger study area is necessary depending on the known seismicity of the area.

(b) Previous earthquake activity. Earthquake activity is measured using a few methods. Richter magnitude is a measure of the energy released by the earthquake while Modified Mercalli Intensity (MMI) is a measure of the effect on humans. Tables are available to convert between Richter and MMI. Peak Ground Acceleration (PGA) is a measure of the maximum amount of movement reached during an earthquake event. It is directly related to the amount of force experienced by a pipeline facility during the event. Peak Ground Velocity (PGV) is the maximum ground speed reached during an earthquake event. PGV is the degree of shaking that a particle of sand would feel during the earthquake event. PGV is a method of assessing possible pipeline damage. When historic (since 1900 or oldest available) earthquake information with values such as magnitude > 4.0 Richter, > VI MMI, PGA ≥ 0.2g, or PGV > 17 cm/s should be considered a threat to pipeline facilities.

(c) Probability of future earthquake activity along fault.

(d) Analyses of leaks or damage attributable to earthquake activity.

11.4 Year of installation.

...

11.5 Pipe parameters.

...

11.6 Other considerations.

(a) Weather-related conditions.
Excessive loading from weather-related conditions that are likely to occur (see guide material under §~~§192.317 and~~ 192.615).
(1) Tornadic activity or high winds.
(2) Heavy snow or ice loading.
(3) Lightning strikes.
(4) Wild (or other) fires.
~~(5) Flooding (see 6 of guide material under §192.613).~~
(b) ...
(c) ...
(d) See 1~~6~~7.3.2 below.

12 PLASTIC TRANSMISSION PIPELINES

12.1 General. ...

...

12.3 Manufacturing threats.

This threat refers to defects of the pipe or fittings that are associated with the manufacturing process. Additional guidance for manufacturing considerations related to plastic pipelines can be found in guide material under §§192.121, 192.123 and 192.613 and OPS Advisory Bulletins (ADBs). See 1~~6~~7.2 below for a list of applicable ADBs.

(a) Potential manufacturing threats.
  (1) Identification of a manufacturing defect may be accomplished as follows.
    (i) By observations of pipe surfaces and fittings during normal construction, operation, and maintenance activities.
    (ii) Through failure analysis, such as after incidents.
    (iii) During review of prior integrity assessment results.
    (iv) By review of Plastic Pipe Database Committee (PPDC) reports. See 1~~6~~7.2.2 below.
  (2) Some examples of pipe defects include the following.
    ...
  ...
(b) Data collection.
  ASME B31.8S, Appendix A4 relates to metallic pipelines, but ...
  (1) Pipe material.
    (i) Acrylonitrile butadiene styrene (ABS).
    (ii) Cellulose acetate butyrate (CAB).
    (iii) Fiberglass reinforced plastic (FRP). See 1~~6~~7.2.4 below for a reference providing specifications on fiberglass pipe.
    ...
  (2) Year of installation.
  Some older plastic pipe materials are susceptible to premature brittle-like cracking (see guide material under §192.613). If pipe material is unknown, the year of installation may provide some indication whether ~~that more~~ susceptible material ~~might have~~ has been installed. See 1~~6~~7.2.1 below. Specific manufacturing years may be of concern for the following materials.
    ...
  (3) ...
  (4) ...

12.4 Construction threats.

...

...

12.6 Third-party damage.

(a) Potential third-party damage threats. ...
(b) Data collection.
  ...
  (5) One-call records.
    (i) Frequency of excavation activity around pipeline.
    (ii) Identity of excavator.
    (iii) Effectiveness of one-call program See 1~~6~~7.3.1 below.
  (6) ...
(c) ...

12.7 Incorrect operations (includes human error).

...

12.8 Weather-related and outside forces.

See guide material under 11.2 and 11.3 for guidance on weather-related and outside forces. ~~Weather-related and outside force threats have the capability to create extreme loading conditions on plastic pipelines (see guide material under §§192.317 and 192.615).~~

~~(a) Potential weather-related and outside forces threats include the following.~~

~~(1) Flooding (see 6 of the guide material under §192.613).~~
~~(2) Frost heave and freeze-thaw cycles.~~
~~(3) Earthquakes.~~
~~(4) Landslides and other downslope material movement (e.g., creep, flows, rock falls/topples, etc.).~~
~~(5) Subsidence.~~
~~(6) Soils that undergo recurrent or cyclical shrink and swell processes (e.g., some clays or manmade soils).~~
~~(76) Extreme loads (e.g., equipment crossings).~~
~~See Section 6 of guide material under §192.613 for additional information regarding unstable slopes, floodings, and subsidence.~~

~~(b) Data collection.~~

~~ASME B31.8S, Appendix A9 generally relates to metallic pipelines, but may be useful as a format for data that should be collected to evaluate a plastic pipeline for weather and outside force damage. The following may be applicable to plastic pipelines and should be considered by the operator.~~

~~(1) Pipe joining method.~~

~~Pipelines that include the following joint types may be more susceptible to leakage or failure from the threat of weather-related and outside forces than pipelines constructed using modern joining methods.~~
~~(i) Mechanical fittings that do not have restraints to prevent pipe pull-out.~~
~~(ii) Solvent cement.~~
~~(iii) Adhesive.~~
~~(iv) Heat fusions with a history of poor or cold fusions.~~

~~(2) Geology, Topography and~~ soil conditions and geohazards.

~~The following topographical areas should be examined to determine if the threat associated with extreme loading conditions exists.~~
~~(i) Slopes prone to movement or other unstable areas and/or unstable ground that would induce additional stresses in a pipeline due to the movement of soil (e.g., creep, downslope material movement). Downslope material movement includes slides, flows, rock falls/topples, etc.~~
~~Areas prone to recurrent or intermittent flooding that causes surface erosion, saturated soils, and/or increased buoyant forces on pipelines.~~
~~(ii) Areas prone to recurrent or intermittent flooding that causes surface erosion, saturated soils, and/or increased buoyant forces on pipelines.~~
~~(iii) Extremely saturated soils that produce buoyant forces on pipelines.~~
~~(A) River and stream crossings.~~
~~(B) Lowlands including floodplains, wetlands, and swamps, etc.~~
~~(C) Coastal areas prone to tidal surges from hurricanes or tropical storms.~~
~~(iviii) Areas prone to frost heave and freeze-thaw cycles due to the presence of with deep frost line depths.~~
~~(iv) Highly expansive or unstable soils (e.g., some clays). Soils that undergo recurrent or cyclical shrink and swell processes (e.g., some clays or manmade soils).~~
~~(vi) Other lLocations with known geologic conditions that contribute to instability (e.g., karst topography and/or sinkholes, underground mining and/or mine collapses, other regional subsidence areas).~~

~~(3) Fault zones.~~

~~The following should be considered in evaluating an earthquake fault zone condition.~~
~~(i) A fault line is considered active if movement has been observed and/or evidence exists of seismic activity (earthquakes) during the last 10,000 years. For the purposes of pipeline seismic evaluations, active fault lines within ~60 miles (~100 km) of the pipeline may be included in the evaluation.~~
~~(i) Proximity of earthquake fault zones to pipeline location.~~
~~(ii) Previous earthquake activity (magnitude 4.0 MMI and greater, or peak ground acceleration (PGA) ≥3.0) within ~60 miles (~100 km) of the pipeline since 1900. Magnitude 4.0 MMI or ≥3.0 PGA has greater potential to damage pipeline facilities).~~
~~(iii) Probability of future earthquake activity along fault.~~

~~(iv) Analyses of leaks or other damage attributable to earthquake activity.~~
~~(4) Weather-related conditions.~~
~~Excessive loading from weather-related conditions that are likely to occur should be considered.~~
~~(i) Tidal surges from hurricanes or tropical storms in coastal areas.~~
~~(ii) Flooding or erosion.~~
~~(iii) Tornado activity or high winds.~~
~~(iv) Heavy snow or ice loading, or frost heave or freeze-thaw cycles.~~
~~(v) Significant lightning.~~
~~(5) Year of installation.~~
~~Some older pipeline facilities were constructed with materials and techniques that are generally not equivalent to modern facilities in terms of strength and integrity. The risk attributable to weather-related and outside forces threat may be commensurate with the age of the pipeline facilities.~~
~~(6) Pipe parameters.~~
~~The following pipe parameters indicate capacity to resist weather-related and outside forces.~~
~~(i) Pipe material and density classification (e.g., high-density, medium-density).~~
~~(ii) Specified wall thickness.~~
~~(iii) Specified outside diameter.~~
~~(iv) Standard dimension ratio (SDR).~~
~~(7) Operations and maintenance records.~~
~~Operators should also review operations and maintenance records (e.g., leak data, patrol data) to determine whether extreme loading conditions are present on their pipelines.~~

12.9 Other threats unique to plastic pipelines.

...

13 CRACK AND CRACK-LIKE DEFECTS

Crack and crack-like defects might be included in the threats of manufacturing, construction, environmentally assisted cracking, or stress corrosion cracking. The defects could include such defects as seam defect, seam corrosion, girth weld cracks, hook cracks, fatigue cracks or crack associated with third -party damage. If crack or crack-like defects are found in a covered segment, the operator must develop a schedule to evaluate all segments with similar characteristics (§192.917(e)(6)). See guide material under §192.712(d) for assistance in evaluating cracks and crack-like defects.

1~~3~~4 DATA INTEGRATION

1~~3~~4.1 General.

(a) Operators must gather and integrate relevant attributes of pipelines containing covered segments (§192.917(b)(1)). This ~~Integrity management begins with an understanding of the~~ pipeline ~~through evaluation of~~ data might already be ~~that is often~~ collected for other regulatory and operational purposes or gathered through the review of existing documentation such as those listed in Table 2 of ASME B31.8S. ~~This data should not be handled in isolation, but may need to be shared with persons responsible for other aspects of pipeline operation~~. Collecting ~~Collection~~ and understanding this ~~the relevant~~ information is ~~the first step in~~ critical to ~~establishing~~ an integrity management program. Data integration might ~~may illuminate~~ identify situations ~~that are in need of attention,~~ or ~~highlight~~ conditions that support an operator's ~~are valuable for~~ safe operation ~~and should be emulated on other portions~~ of the pipeline.

(b) Data integration involves merging individual data elements (aggregation) and analyzing them in their combined context (integration) to identify and evaluate potential threats to the pipeline segment. Data integration may allow an operator to discover threats and risks to a pipeline that ~~would not otherwise appear obvious~~ might not be evident from a review of the various individual data elements on their own.

(c) The operator is required by §192.917(b) to consider data from both covered and similar non-covered segments of the pipeline. The operator's data integration procedure should encompass the ability to merge and use the multiple data elements gathered as described in 3 through 12 above, the information listed in §192.917(b)(1), the elements listed in Table 1 of ASME B31.8S, and other information deemed to be relevant by the operator. ~~The operator is required by §192.917(b) to consider data from both covered and similar non-covered segments of the pipeline.~~

~~Therefore, the operator should consider the following.~~
~~(1) Past incident history including abnormal operations and safety-related condition reports.~~
~~(2) Corrosion control records including pipe inspection reports, CIS, or other surveys.~~
~~(3) Continuing surveillance records.~~
~~(4) Patrolling records.~~
~~(5) Maintenance history.~~
~~(6) Internal inspection records.~~
~~(7) ILI results.~~
~~(8) Direct examinations from direct assessment applications.~~
~~(9) Other conditions specific to each pipeline (e.g., one-call and construction activity, third-party damage).~~

(d) ...

(e) ...

1~~3~~4.2 Common reference system.

...

1~~3~~4.3 Data alignment methods.

...

(c) Electronic.

Numerous geospatial systems are available that support overlaying data elements based on an electronic location identifier. These are generally referred to as geographic information systems (GIS) or management information systems (MIS). To secure the location of the data being processed, most use latitude and longitude which may be obtained from satellite-based GPS devices. When aligning data from various GPS surveys the operator should be aware that GPS accuracy may change based on the equipment used and conditions at time of the survey. ~~See guide material under §192.614.~~

(d) ...

1~~3~~4.4 Integration.

...

1~~3~~4.5 Similar non-covered segment

...

1~~4~~5 THREAT STATUS

(a) Active Threats ...

(b) Inactive Threats

(1) ...

...

(7) An operator does not need to ~~asses~~ assess a threat for the current assessment cycle if that threat status is determined inactive.

Threat	Considerations for Active Status	Considerations for Inactive Status
External Corrosion	• Metallic pipe – always active • Note: Operator must protect metallic pipelines per Subpart I	• Plastic Pipe – always inactive
Internal Corrosion	• Production, storage, or non-pipeline-quality gas transported at any time during the history of the pipeline • Pipeline has been converted from another type of service that is susceptible to internal corrosion • Presence of unmonitored or inoperative ~~known~~ drips, siphons, dead legs, or other liquid holdup points • Evidence of liquids from drips, siphons, dead legs, or other liquid holdup points • Pipe inspection reports indicating evidence of internal corrosion • Lack of complete pipeline operating history, in-line inspection, or ICDA	• It can be demonstrated that a corrosive gas is not being transported, per §192.475(a) • In-line inspection data confirms that a corrosive environment does not exist within the pipeline • ICDA demonstrates that there is no internal corrosion occurring ~~at the most likely locations~~ • Plastic pipe~~-~~ – always inactive
Manufacturing	• Steel pipe vintages with a known history of manufacturing defects • Pipe has joint factor of <1.0 • Pipeline is comprised of low-frequency-welded ERW pipe or flash-welded pipe	None of the following have occurred. • Experienced ~~Operating~~ pressure excursions ~~increases~~ above the maximum operating pressure or MAOP ~~experienced~~ during the preceding five years for ERW pipe only • MAOP increases • Stresses that lead to cyclic fatigue increase

Construction	• Mechanically coupled pipelines • Pipelines joined by means of acetylene girth welds • For girth welds, welding procedures and NDT information are not available to ascertain that the welds are adequate • For fabrication welds, the welding procedures and NDT information are not available to ascertain that the welds are adequate • For wrinkle bends and buckles as well as couplings, reports of visual inspection are not available to review and ascertain their continued integrity • Potential movement of the pipeline from ground settlement or other outside loads causing lateral or axial stresses	None of the following have occurred. • ~~Experienced Operating pressure excursions increases above the maximum operating pressure experienced during the preceding five years~~ • MAOP increases • Stresses that lead to cyclic fatigue increase
Equipment	• Equipment issues are identified during normal maintenance activities, per the requirements of the operator's O&M procedures • Equipment that is the cause of abnormal operations, failure, accident, or incident	• History and review of the records, as required by §§ 192.613, 192.617, 192.603, 192.605, 192.739, and 192.743 • Review of operating history failures and abnormal operations records, as evaluated by integrity personnel, determines no unusual trends and no new issues • Status of existing preventative ~~measures~~ and mitigative measures deemed effective
Third-Party Damage	• Always active • Operator must (§192.935(b)(1)) monitor excavation activities and damages	
~~Incorrect Operations~~ Human Error (Incorrect Operations)	• Always active • Operator must (§192.617) evaluate failures and determine if incorrect operations lead to the failure	
Weather-Related and Outside Forces	• Always active • Operator must (§192.935(b)(2)) monitor and take measures to reduce the risk from weather related and outside force damage	

TABLE 192.917i ~~ii~~

1~~5~~6 RISK ASSESSMENT

1~~5~~6.1 General.

...

1~~5~~6.2 Likelihood of failure.

...

1~~5~~6.3 Consequence of failure.

...

1~~5~~6.4 Risk assessment models.

ASME B31.8S, Paragraph 5.5 lists the following four approaches to risk assessment.

(a) Subject matter expert (SME) risk models.

...

...

(e) See 1~~5~~7.1.1~~6~~7 below for a reference providing additional information on risk assessment.

1~~5~~6.5 Selection of risk model.

The approach selected by the operator should have the following characteristics.

(a) Identification of potential events or conditions that are threats to system integrity.

(b) Evaluation of likelihood and consequences of failure.

(c) Determination of ~~risk ranking to prioritize~~ prioritization of integrity assessments.

(d) Development of mitigating action.

(e) Provision for data feedback and validation.

(f) Incorporation of results and lessons-learned from previous ~~Continuous updating for~~ risk assessments ~~and~~ to enhance ~~it's~~ the effectiveness of the model.

1~~5~~6.6 Risk reassessments.

...

1~~5~~6.7 Validation.

...

1~~5~~6.8 Records.

...

1~~6~~7 REFERENCES

1~~6~~7.1 Steel pipe.

1~~6~~7.1.1 Chapter V of GPTC-Z380-TR-1, "Review of Integrity Management for Natural Gas Transmission Pipelines," an ANSI Technical Report by GPTC, November 18, 2001 (Withdrawn 3/30/12), AGA Catalog Number X69806; available at GPTC website.

1~~6~~7.1.2 "Improvement of External Corrosion Direct Assessment Methodology by Incorporating Soils Data," https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=118.

17.1.3 United States. Department of Agriculture, Natural Resources Conservation Service. Web Soil Survey https://websoilsurvey.sc.egov.usda.gov/App/WebSoilSurvey.aspx

1~~6~~7.1.~~3~~4 "Field Guide for Investigating Internal Corrosion of Pipelines," Richard Eckert, published by NACE International, 2003.

1~~6~~7.1.~~4~~5 GRI-02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology" (see §192.7).

1~~6~~7.1.~~5~~6 NACE SP0106, "Control of Internal Corrosion in Steel Pipelines and Piping Systems."

1~~6~~7.1.~~6~~7 Section 4.3.2 of NACE SP0192-12, "Monitoring Corrosion in Oil and Gas Production with Iron Counts."

1~~6~~7.1.~~7~~8 NACE SP0204, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology."

1~~6~~7.1.~~8~~9 OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study", Michael Baker Jr., Inc., January 2005, at: http://primis.phmsa.dot.gov/iim/docstr/SCC_Report-Final_Report_with_Database.pdf.

1~~6~~7.1.~~9~~10 ASME 100396, "History of Line Pipe Manufacturing in North America.

1~~6~~7.1.~~10~~11 "Integrity Characteristics of Vintage Pipelines," INGAA.

1~~6~~7.1.~~11~~12 "Dealing with Low-Frequency-Welded ERW Pipe and Flashwelded Pipe with Respect to HCA-related Integrity Assessments," John F. Kiefner, 2002, www.kiefner.com.

1~~6~~7.1.~~12~~13 OPS Technical Task Order Number 5, "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation," Final Report, Michael Baker Jr., Inc., et al, at: http://primis.phmsa.dot.gov/iim/docstr/TTO5_LowFrequencyERW_FinalReport_Rev3_April2004.pdf.

1~~6~~7.1.~~13~~14 OPS Alert Notices and Advisory Bulletins:

ALN-88-01 (Jan 28, 1988)	Operational failures of pipelines constructed with ERW prior to 1970
ALN-89-01 (Mar 8, 1989)	Update to ALN-88-01
ADB-09-01 (74 FR 23930, May 21, 2009)	Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe.
ADB-2014-04 (79 FR 56121, Sept. 18, 2014)	Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service

TABLE 192.917ii

1~~6~~7.1.~~14~~15 "Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines," Final Report 05-12R, John F. Keifner, 2007, at: http://primis.phmsa.dot.gov/gasimp/docs/Evaluating_Stability_of_Defects.pdf.

1~~6~~7.1.~~15~~16 Section 841.231 of ASME B31.8, "Gas Transmission and Distribution Piping Systems" (see §192.7).

1~~6~~7.1.~~16~~17 "Pipeline Risk Management Manual," W. Kent Muhlbauer, Gulf Publishing Company, ISBN: 0750675799.

1~~6~~7.2 Plastic pipe.

1~~6~~7.2.1 OPS Advisory Bulletins:

ADB-86-02 (Feb. 26, 1986)	Plastic Piping, Mechanical Coupling
ADB-99-01 (64 FR 12211, Mar. 11, 1999)	Susceptibility of Certain Polyethylene Pipe Manufactured by Century Utility Products, Inc. to Premature Failure Due to Brittle-Like Cracking
ADB-99-02 (64 FR 12212 Mar. 11, 1999)	Potential Susceptibility of Plastic Pipe Installed Between the [Years] 1960 and the Early 1980s to Premature Failure Due to Brittle-Like Cracking
ADB-02-07	Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe

(67 FR 70806, Nov. 26, 2002)	
ADB-02-07 Corr. (67 FR 72027, Dec. 03, 2002)	Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe; Notice; correction
ADB-07-02 (72 FR 51301, Sept. 6, 2007)	Updated Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe
ADB-07-02 Corr. (73 FR 11192, Feb. 29, 2008)	Updated Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe
ADB-12-03 (77 FR 13387, Mar. 6, 2012)	Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation

TABLE 192.917iii

1~~6~~7.2.2 Plastic Pipe Database Committee (PPDC) reports at: www.aga.org/Kc/OperationsEngineering/ppdc/Status%20Reports/Pages/default.aspx

1~~6~~7.2.3 Section 4 of Guide Material Appendix G-192-8, Distribution Integrity Management Program (DIMP).

1~~6~~7.2.4 API Specification 15HR High-Pressure Fiberglass Line Pipe.

1~~6~~7.3 Applicable to both steel and plastic pipe.

1~~6~~7.3.1 "Results of State Damage Prevention Program Characterizations," at: https://primis.phmsa.dot.gov/comm/sdppcdiscussion.htm

1~~6~~7.3.2 "Guideline for Assessing the Performance of Oil and Natural Gas Pipeline Systems in Natural Hazard and Human Threat Events," American Lifelines Alliance.

GMA G-192-1

2 GOVERNMENTAL DOCUMENTS

OPS ADB-2014-03	Advisory Bulletin – Construction Notification (79 FR 54777, Sept. 12, 2014	§191.22
OPS ADB-2014-04	Advisory Bulletin – Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service (79 FR 56121, Sept. 18, 2014)	§192.917
OPS ADB-2014-05	Advisory Bulletin – Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics (79 FR 61937, Oct. 15, 2014)	GMA G-192-3