Editorial Note: Approved, balloted language is in **dark blue**; this will be published in Addendum 1 to 2025 guide any day now (i.e. July).

Section 192.475

1 GENERAL

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2 GAS QUALITY

(a) When gas supplies change, consider the potential effect on the pipeline and whether additional monitoring and mitigation might be warranted.

(b) Changes in volume mix from multiple suppliers on the same line might affect the blend in the pipeline. Volume mixes may have seasonality or other variations.

(c) Operators can review interconnect or tariff agreements to ensure any potentially new corrosive constituents are accounted for in the internal corrosion monitoring programs.

(d) Monitoring technologies are selected based on feasibility and practicality of identifying the probable corrosive constituents expected for the line. Chromatographs might have historically only provided basic gas quality data, such as BTU and moisture content. Operators might need to review their monitoring practices and equipment based on their pipeline conditions.

(e) Monitoring programs may employ real-time continuous monitoring via probes, coupons, or other devices in conjunction with periodic sampling. ~~Both g~~Gaseous and liquid phases ~~should be considered~~ as well as microbic activity may require separate monitoring methods where applicable.

(f) Testing or visual examinations of internal pipe surfaces are valuable data that can supplement or confirm monitoring program data.

(g) The operator can establish action thresholds for each corrosive constituent for mitigation, preventive measures, or additional monitoring.

(h) Both individual and combined effect of corrosive constituents might be considered. Presence of free water for example might exacerbate the corrosivity of other constituents. Similarly, an operator might consider both the partial pressure and amount of a constituent in the gas phase when determining corrosion monitoring and mitigation criteria.

3 DESIGN CONSIDERATIONS

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4 DETECTION METHODS

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5 MONITORING TYPES *{ Note: GM 5 below was copied from GM 4.7 under §192.917}*

(a) Gas. When analyzing for internal corrosion, partial pressures and gas chemistry are important considerations. Typical gas analyses ~~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 5(a) and 5(b) 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

(2) *Hydrogen sulfide (H_2S).*

(i) H_2S may be a normal constituent in natural gas and can also be formed due to microbiologically influenced corrosion (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 calculated to be ~~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, might result in increased internal corrosion. Immediate sample testing is recommended because pH changes upon exposure to the atmosphere.

(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 might indicate corrosion of steel. A manganese to iron ratio between 1:50 and 1:200 might 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 5(c) below.

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

(iv) ~~When analyzing iron and manganese counts,~~ ~~t~~The system parameters (e.g., flow rate, amount of water, temperature) ~~should be reviewed and will~~ influence scaling tendencies~~y 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 found inside the pipe can be an ~~leading or lagging~~ indicator of corrosion. ~~should be sampled whenever they are found inside the pipe. Bacteria cultures (see 3(d) below) and pH need to be taken immediately upon exposing the solids, because the values might 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 might 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 might often cause acceleration of pitting. Iron sulfide might commonly be found as black dust inside of pipelines.

(2) *Mineral scale.* Mineral scale could contain a variety of components and compounds, depending on the contaminants and environment. Scale ~~should~~ can 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.~~ Evaluating manganese to iron ratio can help distinguish the source of the manganese (i.e., whether environmentally occurring or from the pipeline steel itself).

(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.

(d) Bacteria culture tests.

Liquids and solids collected ~~should~~ can ~~may~~ be tested for the presence of both acid-producing bacteria (APB) and sulfate-reducing bacteria (SRB) through the use of culture tests. Separate test kits and incubation periods are used for each type of bacteria. The presence of bacteria in the system does not necessarily indicate that MIC is occurring. However, further investigation needs to be performed. Exposure to the atmosphere might affect the viability of bacteria; therefore, immediate testing is recommended.

(e) Internal probes or coupons.

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

6 MONITORING OR TESTING FREQUENCY

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{End of Changes}

{NOTE: Language from most recent TR 22-66 recirculation ballot is in blue. While approved, this has not yet made it into published 2025 edition.}

Section 192.917

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 might ~~may~~ contribute to the failure of a pipe segment, which assessment techniques are appropriate, and which preventative and mitigative measures ~~should be to~~ implement~~ed~~. 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 (§192.917(b)).

(b) Section 192.917(b) requires that operators 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). Information within ASME B31.8S, Appendix A might also be helpful when collecting this data.

(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 (§192.907(a)).

(d) Validated data is the preferred input where possible. Data acquired from routine O&M activities can ~~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~~ Mapping tools ~~to~~ can 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) An operator must consider potential threats per §192.917(a). If the operator is missing data, conservative assumptions should be used and documented in the risk analysis.

(h) A threat may be active or inactive for a specific risk assessment cycle; however, threats to a pipeline can 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) 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 (§192.917(b)(1)). Communication between O&M and integrity personnel is a key component to evaluating threats.

(j) 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 15 addresses threat status, Section 16 addresses risk assessment, and Section 17 provides a list of references.

2 IDENTIFICATION OF THREATS TO STEEL PIPELINES

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3 EXTERNAL CORROSION

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4 INTERNAL CORROSION

In evaluating the threat of internal corrosion, §192.917(b)(1) 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…

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 internal corrosion evaluations and assessments on pipelines due to potential new locations of liquid accumulation.

4.4 Wall thickness. …

4.5 Pipe diameter. …

4.6 Prior assessments. …

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~~ ~~analyzed for indications of~~ analyses or trending might ~~may~~ identify changes to the threat of internal corrosion. See §192.477 for monitoring requirements and guide material under §192.475. Further reference materials are in 17 below.

4.8 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~~ could ~~may~~ vary 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 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 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 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 might affect ~~may impact on~~ existing defects~~; this~~ and should be evaluated as part of the Management of Change process (§§ 192.13(d) and 192.911). 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 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) …

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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 17.1.8 below. Pipeline segments may be susceptible to two types of SCC; high pH and near-neutral pH.

(b) …

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5.1 Age of pipe. …

5.2 Operating stress level (percent SMYS)…

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~~ can be more susceptible to high pH SCC because of high discharge temperatures. Flow reversals will alter this

input for the threat evaluation, prompting a new threat analysis for affected pipeline segment(s). Segments historically downstream of compressor stations remain susceptible to SCC due to their prior exposure to those stresses and 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. …