TR 19-22 - Monitoring Pipelines for Internal Corrosion

TR Number	**19-22**
Primary	192.477, ~~192.478 {added 192.478 from TR 22-61}~~
Secondary	192.475
Purpose	1) Review existing GM and add additional means of monitoring pipelines for internal corrosion as appropriate. ~~2) Review and develop GM as appropriate in light of Amendment 192-132 {added purpose from 192.478 from TR 22-61}~~ 3) Update existing and balloted GM as necessary in light of court ruling vacating 192.478.
Origin/ Rationale	1) email 6/13/2019 from Mary Friend There are a number of other methods which can be used to monitor pipelines for internal corrosion. There is no mention of sampling (both liquid gas and solids), bacteria cultures, partial pressures, etc. GM 192.917 Section 4 outlines a number of methods that may be used to determine if internal corrosion is present. The GM for 192.477 which is the internal corrosion monitoring lacks a lot of detail that could be included and explained. Perhaps at least provide a cross reference to 192.475 for additional information. And there is no discussion in either of these sections regarding written plans and action levels for remediation. 2) Amdt. 192-132 added new 192.478 titled: Internal corrosion control: Onshore transmission monitoring and mitigation. 3) Appelate court ruling issued 8/16/24 vacated §192.478.
Assigned to	IMP/Corr

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

Language previously approved as GM under 192.478 and now moved to 192.475 is shown in green text.

Section 192.475

1 GENERAL

In the presence of free water, gases containing certain constituents, such as carbon dioxide, hydrogen sulfide, sulfur, microbes, and oxygen, can be corrosive to steel pipelines. Pipeline liquids ~~may~~ might combine with these constituents and cause corrosion that ~~may~~ could be detrimental to pipeline integrity. ~~Because of this, monitoring and evaluating corrosion, operating conditions, gas quality, and liquids found in pipelines are~~ Consequently, the following might be important elements of internal corrosion control programs.

(a) Defining gas quality parameters in purchase agreements.

(b) Monitoring and evaluating:
   (1) Corrosion.
   (2) Operating conditions.
   (3) Pipeline geometry and elevation changes,
   (4) Gas quality results ~~(see guide material under §192.478)~~.
   (5) Liquids to identify the presence of corrosive constituents.

(c) Establishing gas, liquid, and solid testing criteria and specify when remediation actions are required based on the results.

(d) Analytical elements such as corrosion rate analysis, corrosion observation results, and overall data trending.

(e) See guide material under §§ 192.476, 192.477, and 4 of the guide material under §192.917 for further information.

The ~~following are~~ guide material below provides considerations for managing internal corrosion.

2 GAS QUALITY ~~CORROSIVE CONSTITUENTS~~

(a) When gas supplies change, consider the potential ~~impact~~ 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 ~~should~~ 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 ~~should be~~ 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 gaseous and liquid phases should be considered as well as microbic activity where applicable.

(f) Testing or visual examinations of internal pipe surfaces ~~(see §192.475)~~ are valuable data that can supplement or confirm monitoring program data.

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

(h) Both individual and combined effect of corrosive constituents ~~should~~ 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.

~~2~~ 3 DESIGN CONSIDERATIONS

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~~3~~ 4 DETECTION METHODS

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5 MONITORING TYPES *{LB Note: GM 5 below is 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 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 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~~ might result in increased internal 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~~ might indicate corrosion of steel. A manganese to iron ratio between 1:50 and 1:200 ~~may~~ 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 ~~may~~ might 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 3(d) below) and pH need to be taken immediately upon exposing the solids, because the values ~~may~~ 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 ~~may~~ 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 ~~may~~ might often cause acceleration of pitting. ~~It~~ Iron sulfide ~~may~~ might commonly be found as black dust inside of pipelines.

(2) *Mineral scale.* Mineral scale ~~may~~ could 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.

(d) 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.

(e) Internal probes or coupons.

Internal probes or corrosion coupons ~~may~~ 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.

~~4~~ 6 MONITORING OR TESTING FREQUENCY

The following considerations could ~~impact~~ affect the frequency of monitoring or testing.

(a) Location and history of water removal.

(b) ...

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(o) System design (e.g., materials of construction, pipe wall thickness, pigging facilities, presence of drips).

(p) Compliance with federal, state, or local regulations. See §192.477 regarding coupons, probes, and similar devices.

~~5~~ 7 MITIGATIVE MEASURES

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~~6~~ 8 REFERENCES

(a) ...

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(d) NACE RP0175, "Control of Internal Corrosion in Steel Pipelines and Piping Systems" (Revised 1975; Discontinued).

(e) NACE SP0106, "Control of Internal Corrosion in Steel Pipelines and Piping Systems."

(~~e~~ f) NACE SP0192, "Monitoring Corrosion in Oil and Gas Production with Iron Counts."

(~~f~~ g) NACE SP0775, "Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations."

(~~g~~ h) NACE TM0194, "Field Monitoring of Bacterial Growth in Oilfield Systems."

(~~h~~ i) NACE 3D170, Technical Committee Report, "Electrical and Electrochemical Methods for Determining Corrosion Rates" (Revised 1984; Withdrawn 1994).

(~~i~~ j) "Evaluation of Chemical Treatments in Natural Gas System vs. MIC and Other Forms of Internal Corrosion Using Carbon Steel Coupons," Timothy Zintel, Derek Kostuck, and Bruce Cookingham, Paper # 03574 presented at CORROSION/03 San Diego, CA.

(~~j~~ k) "Field Guide for Investigating Internal Corrosion of Pipelines," Richard Eckert, NACE Press, 2003.

(~~k~~ l) "Field Use Proves Program for Managing Internal Corrosion in Wet-Gas Systems," Richard Eckert and Bruce Cookingham, Oil & Gas Journal, January 21, 2002.

(~~l~~ m) "Internal Corrosion Direct Assessment," Oliver Moghissi, Bruce Cookingham, Lee Norris, and Phil Dusek, Paper # 02087 presented at CORROSION/02 Denver, CO.

(~~m~~ n) "Internal Corrosion Direct Assessment of Gas Transmission Pipeline - Application," Oliver Moghissi, Laurie Perry, Bruce Cookingham, and Narasi Sridhar, Paper # 03204 presented at CORROSION/03 San Diego, CA.

(~~n~~ o) "Microscopic Differentiation of Internal Corrosion Initiation Mechanisms in a Natural Gas System," Richard Eckert, Henry Aldrich, and Chris Edwards, Bruce Cookingham, Paper # 03544 presented at CORROSION/03 San Diego, CA.

Section 192.477

(a) ~~Gas quality, pipeline design, and history of internal corrosion might influence the need to monitor for internal corrosion. Operators should consider developing an internal corrosion monitoring plan to address routine testing of gas quality and provide guidance when devices or other methods are necessary to evaluate internal corrosion. The internal corrosion monitoring plan should establish gas, liquid, and solid testing criteria and specify when remediation actions are required based on the results. Other plan elements may include operational and physical system data, corrosion monitoring results, corrosion rate analysis, corrosion observation results, and overall data trending.~~ See guide material under §§ 192.475, 192.476~~, and 192.478~~, and 4 of the guide material under §192.917 for further information regarding internal corrosion monitoring and mitigation plans, design for internal corrosion control, and internal corrosion threats, respectively.

(b~~a~~) Devices that can be used to monitor internal corrosion or the effectiveness of corrosion mitigation measures include hydrogen probes, corrosion probes, corrosion coupons, test spools, and nondestructive testing equipment capable of indicating loss in wall thickness.

(c~~b~~) Consideration should be given to the site selection and the type of access station used to expose the device to on-stream monitoring. It is desirable to incorporate a retractable feature in the monitoring station to avoid facility shutdowns during periodic inspections, such as weight loss measurements, and for on-stream pigging of the facility.

(d) Consideration should be given regarding the suitability of technologies that monitor potentially corrosive constituents reasonably expected to occur in the line. Gas quality, volumes, pressures, and flows might affect feasibility for a given technology.

(e~~c~~) A written procedure should be established to determine that the monitoring device is operating properly.

(f~~d~~) See guide material under §192.475 if internal corrosion is discovered or is not under mitigation.

~~(g) See guide material under §192.478 for monitoring and mitigation program guidance.~~

~~Section 192.478~~

{LB note: Previously proposed GM under §192.478 is removed and portions are being moved to GM under §192.475 and are shown above in green text.}

{Publication Note: Since Amendment 192-138 was issued on January 15, 2025 and removes §192.478, §192.478 should be removed from the Guide.}

GMA G-192-1

1.9 CORROSION RELATED (Continued)		
...	...	...
NACE SP0106	Control of Internal Corrosion in Steel Pipelines and Piping Systems	§192.475 §192.476 ~~§192.478~~ §192.917
...	...	...
NACE SP0192	Monitoring Corrosion in Oil and Gas Production with Iron Counts	§192.475 ~~§192.478~~ §192.917

3.2 CORROSION RELATED	
...	...
"Field Guide for Investigating Internal Corrosion of Pipelines," Richard Eckert, NACE International, 2003	§192.475 ~~§192.478~~ §192.917