§192.471

External corrosion control: Test leads.

[Effective Date: 08/01/71]

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

[Issued by Amdt 192-4, 36 FR 12297, June 30, 1971]

GUIDE MATERIAL

1 INSTALLATION METHODS

Some acceptable methods include the following.

1.1 Thermit welding.

(a) Steel. Attachment of electrical leads directly to steel pipe by the thermit welding process using copper oxide and aluminum powder. The thermit welding charge should be limited to a 15-gram cartridge.

(b) Cast iron. Attachment of electrical leads directly to cast or ductile-iron pipe by the thermit welding process using copper oxide and aluminum powder. The thermit welding charge should be limited to a 32-gram cartridge.

1.2 Solder connections.

Attachment of electrical leads directly to steel pipe with the use of soft solders or other materials that do not involve temperatures exceeding those for soft solders.

1.3 Brazing.

Attachment of electrical leads to steel pipe by brazing, provided that the pipeline operates at less than 29% SMYS.

1.4 Mechanical connections.

Mechanical connections which remain secure and electrically conductive.

2 OTHER CONSIDERATIONS

For convenience, conductors may be coded or permanently identified. Wire should be installed with slack. Damage to insulation should be avoided. Repairs should be made if damage occurs. Test leads should not be exposed to excessive heat or excessive sunlight.

§192.473

External corrosion control: Interference currents.

[Effective Date: 09/05/78]

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]

GUIDE MATERIAL

1 REFERENCE

A reference is NACE SP0169, Section 9.

2 INSTALLATION CONSIDERATIONS

(a) Attention should be given to a new pipeline's physical location, particularly if the location may subject the pipeline to stray electrical currents from other facilities, such as the following.
   (1) Other pipelines or utilities with associated cathodic protection (CP) systems.
   (2) Rail transit systems.
   (3) Mining or welding operations.
   (4) Induced currents from electrical transmission lines.

(b) To the extent possible, the operator should identify and plan for the mitigation and control of anticipated stray electrical currents prior to construction. As soon as practicable after construction of the pipeline or facility to be protected is completed, the operator should implement monitoring, testing, and mitigation plans to control the effects of stray electrical currents. The rate of corrosion caused by stray electrical current can be higher than the rate of corrosion resulting from galvanic action.

3 EXTERNAL CORROSION CONTROL EFFECTIVENESS

Once the interference control methods have been established, periodic tests and inspections should be conducted to ensure their continued effectiveness. See §192.465(b), (c), and (d) for inspection and test requirements for CP rectifiers and interference bonds.

§192.475

Internal corrosion control: General.

[Effective Date: 07/13/98]

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found —

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m^3) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 GENERAL

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

2 DESIGN CONSIDERATIONS

If it is anticipated, or has been determined, that the gas to be transported is corrosive, the following should be considered for the design of the pipeline system.

(a) Selection of special materials.
  (1) Nonmetallic materials.
  (2) Nonferrous metals.
  (3) Special alloy steels.
(b) Selection of steel pipe.
  (1) Increased wall thickness.
  (2) Pipe grade.
  (3) Metallurgy.
  (4) Internal coating.
(c) Effect of high, low, or no flow velocities and liquid accumulation.
(d) Piping configurations that can contribute to changes in flow velocities, which can cause the free water and constituents to settle out of the gas stream and build into concentrations that could lead to internal corrosion. Examples of these configurations include the following.
  (1) Dead ends.
  (2) Sags or low spots.
  (3) Fittings and mechanical connections.
  (4) Sharp bends (vertical or horizontal).
  (5) Sudden diameter changes.
  (6) Drips.
  (7) Crossover piping between systems with normally closed valves.
(e) Corrosion monitoring devices and access fittings for them.
(f) Physical location of the pipe, since external climate, heat sources, and environment can affect internal temperature.
(g) Selection and location of liquid separation, dehydration, or gas scrubbing equipment.

3 DETECTION METHODS

The following may be used to detect internal corrosion.

(a) Visual inspection of piping and components.
  (1) Access ports.
  (2) Selective cut-outs.
(b) Corrosion monitoring devices.
  (1) Corrosion coupons and spools.
  (2) Resistance probes.
  (3) Polarization probes.
  (4) Hydrogen probes and patches.
  (5) Electrochemical probes.
(c) Sampling.
  (1) Liquids analysis.
    (i) Chemical composition.
    (ii) Microbiological composition.
  (2) Gas composition analysis.
  (3) Solids analysis.
    (i) Chemical composition.
    (ii) Microbiological composition.
(d) Trending of analytical data.
(e) Internal inspection tools.
(f) Ultrasonic inspection.
(g) Radiography.
(h) Failure analysis.
(i) Internal corrosion direct assessment.

4 FREQUENCY

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

(a) Location and history of water removal.
(b) Age and condition of pipe and drips.
(c) Internal corrosion history, including leaks and ruptures.
(d) Liquids composition.
(e) Gas composition.
(f) System operating parameters (e.g., temperature, pressure, volumes transported, wet system vs. dry).
(g) System physical layout (e.g., topography).
(h) Flow characteristics.
(i) Proximity to dwellings and the public.
(j) Class location, HCAs, or identified sites (see §192.903).
(k) Pipeline segments downstream of production or storage fields where free water and constituents might accumulate.
(l) Solids composition.
(m) Past inspection results.
(n) Past results obtained using corrosion monitoring devices.
(o) System design (e.g., materials of construction, pipe wall thickness, pigging facilities, presence of drips).

5 MITIGATIVE MEASURES

The following measures can be used to mitigate internal corrosion.

(a) Control of moisture level (e.g., by dehydration, separation, or temperature control).
(b) Reduction of corrosive constituents (chemical or biological) in the gas.

(c) Internal coating.
(d) Liquids or solids removal.
    (1) Pigging - frequency of pigging will depend on both the volume and the analysis of materials received during pigging operations.
    (2) Drips - frequency of operation will depend on both the volume and analysis of materials removed.
    (3) Separators - frequency of maintenance will depend on changes in results from liquids analyses.
(e) Chemical or biological treatments.
    (1) Treatments should not cause deterioration of piping system components.
    (2) Treatments should be compatible with the following.
        (i) Gas being transported.
        (ii) Downstream gas utilization and processing equipment.
        (iii) Any other treatments.

6 REFERENCES

(a) See 2 of the guide material under §192.53.
(b) GRI-02/0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology."
(c) NACE MR0175, "Materials for Use in H_2S-Containing Environments in Oil and Gas Production."
(d) NACE RP0175, "Control of Internal Corrosion in Steel Pipelines and Piping Systems" (Revised 1975; Discontinued).
(e) NACE SP0192, "Monitoring Corrosion in Oil and Gas Production with Iron Counts."
(f) NACE SP0775, "Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations."
(g) NACE TM0194, "Field Monitoring of Bacterial Growth in Oilfield Systems."
(h) NACE 3D170, Technical Committee Report, "Electrical and Electrochemical Methods for Determining Corrosion Rates" (Revised 1984; Withdrawn 1994).
(i) "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) "Field Guide for Investigating Internal Corrosion of Pipelines," Richard Eckert, NACE Press, 2003.
(k) "Field Use Proves Program for Managing Internal Corrosion in Wet-Gas Systems," Richard Eckert and Bruce Cookingham, Oil & Gas Journal, January 21, 2002.
(l) "Internal Corrosion Direct Assessment," Oliver Moghissi, Bruce Cookingham, Lee Norris, and Phil Dusek, Paper # 02087 presented at CORROSION/02 Denver, CO.
(m) "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) "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.

§192.476

Internal corrosion control: Design and construction of transmission line.

[Effective Date: 05/23/07]

(a) Design and construction. Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

(b) Exceptions to applicability. The design and construction requirements of paragraph (a) of this section do not apply to the following:

(1) Offshore pipeline; and

(2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

(c) Change to existing transmission line. When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

(d) Records. An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

[Issued by RIN 2137-AE09, 72 FR 20055, Apr. 23, 2007]

GUIDE MATERIAL

1 GENERAL

This guide material addresses liquids that cause internal corrosion (i.e., liquids that contain water).

(a) In accordance with NACE SP0106, "Control of Internal Corrosion in Steel Pipelines and Piping Systems," if liquid water is not present in the steel pipeline, corrosion will not occur. Section 192.476 uses the term "*liquids*" when the concern of internal corrosion pertains only to liquids that act as an electrolyte (liquid water). The term "*liquid water*" will be used in the guide material.

(b) NACE SP0106 states that because of the complex nature and interaction between constituents (e.g., carbon dioxide, hydrogen sulfide) that are found in gas or liquid water, certain combinations of these impurities transported in the pipeline might affect whether a corrosion condition exists. Appendix A (non-mandatory) of this standard provides an example of a typical gas quality specification.

(c) The term "*significant potential for internal corrosion*" as used in §192.476(a)(3) means that the risk of internal corrosion is known to exist in like situations to the degree that the serviceability or the design life of the pipeline segment might be negatively affected.

2 DETERMINATION OF WHAT CONSTITUTES IMPRACTICABLE AND UNNECESSARY

2.1 Impracticable.

Examples of conditions that may make it impracticable to design and construct features to reduce the risk of internal corrosion include the following. For most of these examples, the operator should consider installing liquid water removal or monitoring devices at an upstream location feasible for installation.

(a) A low spot or angle created when a pipeline segment is bored in and where liquid water is expected to accumulate.
(b) Pipeline segments installed in casings in such a configuration that liquid water is expected to accumulate.
(c) Water crossings or where pipeline segments are installed in marshes.
(d) Very deep pipelines or pipelines in extremely congested rights-of-way installed in a configuration where liquid water is expected to accumulate.
(e) Changes to compressor, meter, and regulator station facilities where there is limited space and access.

2.2 Unnecessary.

Examples of conditions that may make it unnecessary to design and construct features to reduce the risk of internal corrosion include the following.

(a) The operator transports:
  (1) Vaporized LNG where no other source of supply or interconnect exists. This gas is very dry and is extremely unlikely to produce internal corrosion.
  (2) Gas that meets the typical gas quality specification in NACE SP0106, Appendix A.
  (3) Gas with a velocity such that impurities are kept suspended in the gas stream, minimizing the accumulation of corrosive liquid.
(b) The operator uses:
  (1) Chemicals (e.g., corrosion inhibitors, biocides) to mitigate the occurrence of internal corrosion.
  (2) Moisture analyzers or liquid water removal devices upstream of the pipeline segment to monitor for liquid water.
  (3) Gas quality monitoring upstream, provided that short-term upsets would be detected and managed.
(c) The operator installs:
  (1) In-kind replacement of pipe, valve, fitting, or other line components with no known internal corrosion with like size and like configuration. For example, replacement of a small section of 24-inch pipe with 24-inch pipe, or replacement of a full-port ball valve with a full-port ball valve.
  (2) Additions to meter stations or regulating stations, such as an additional meter run or addition of a relief valve.
  (3) Pipe with no inclination angles exceeding the critical angle. See NACE SP0206, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)."
  (4) Pipeline for a temporary operating period of service not to exceed 5 years beyond installation, provided that the corrosion rate would not achieve a predicted failure pressure (PFP) below operating pressure in that time period.
  (5) Pipeline in a normally dry gas system where short-term upsets would blend with a sufficient volume of dry gas to make the risk of internal corrosion negligible (e.g., buried below the frost line and away from large temperature differentials).
  (6) Pipeline with no in-line pressure reducing devices that would precipitate the fall-out of liquid water into the pipe segment.

3 DESIGN CONSIDERATIONS

3.1 General.

(a) The incorporation of design features to address internal corrosion improves the ability of the operator to prevent internal corrosion and to perform maintenance activities to control internal corrosion. There are many design features that an operator can incorporate to address the risk of internal corrosion. See guide material under §192.475.
(b) To address the design requirements of reducing the risk of internal corrosion, an operator should address design features in the order of (1) configuration, (2) liquid removal, and then (3) monitoring.
(c) If the configuration of the pipeline is such that the risk that liquid water will collect is nonexistent or minimal, the operator may not need to design for liquid water removal or monitoring.
(d) If the configuration would allow liquid water to collect, the operator would be required to design for effective liquid water removal. Installation of these features would satisfy §192.476(a) requirements and monitoring would not be required, provided a program for liquid water removal is instituted. Examples where liquid water could accumulate include the following.
    (1) Sags.
    (2) Bases of inclines.
    (3) Valves.
    (4) Manifolds.
    (5) Dead-legs.
    (6) Traps.
(e) Where liquid water is likely to collect, and the liquid water removal system is not provided or does not effectively remove liquid water and there is significant potential for internal corrosion, devices for monitoring are required (see §192.476(a)(2)).

3.2 Configuration design.

Examples of ways to reduce the risk that liquids will collect in a line include the following.

(a) Minimize dead ends, such as pipe stubs downstream of stopple fittings, and low areas.
(b) Minimize aerial crossings, since these can result in variation of temperature.
(c) Design for turbulent flow, in which the velocity at a given point varies erratically in magnitude and direction, to decrease the chance of liquid water separating from the flow stream and accumulating.
(d) Minimize the entry of water and corrosive gases at receipt locations. For example, liquid water removal devices (e.g., separators) at the inlet to compressor, meter, and regulator stations can protect station piping from the entry of liquid water.
(e) Provide slam valves to isolate systems when corrosive gas is expected. A "slam valve" is a shut-off valve that stops the flow of gas in the event that a predetermined criteria is met.
(f) Apply coatings to interior walls to inhibit internal corrosion.
(g) Design for pigging.
(h) Design for the injection of corrosion inhibitors.
(i) Design with no inclination angles exceeding the critical angle at normal operating conditions (see NACE SP0206) so that liquid water will not accumulate, because the gas velocity will carry the liquid water through the pipeline.
(j) On new pipelines with new receipt meters, design the configuration to accommodate equipment to monitor moisture and gas quality with control systems, such as slam valves or secondary liquid separation or dehydration equipment.
(k) Maintain a flow velocity sufficient to prevent corrosive liquids from dropping out of the gas stream.
(l) Evaluate the seasonal nature of delivery and capacity patterns and design to avoid no-flow or low-flow conditions.
(m) Include equipment to evaluate gas quality characteristics (e.g., water, carbon dioxide, H_2S, oxygen).
(n) Provide for blending, such that liquid water will be reabsorbed into the gas stream where there is potential for liquid water to enter the line during upset conditions.
(o) See NACE SP0106, Sections 3, 5, and 7 for internal corrosion design considerations.

3.3 Liquid removal.

(a) Install equipment to allow liquid water sampling at key areas, such as pig traps, isolated sections with no flow, dead ends, and river and road crossings.

(b) Implement a pigging or sweeping program for cleaning of the pipeline so that if liquid water does collect for a short period of time, the liquid water can be removed through pigging or sweeping at necessary intervals. "Sweeping" is a process in which the gas stream has a velocity high enough to move liquids downstream to a collection point.

(c) Install drips or other liquid water removal facilities along the pipeline where liquid water is expected to accumulate and implement a drip management program to blow drips and sample liquid water.

(d) See NACE SP0106, Sections 3, 5, and 7 for internal corrosion control methods.

3.4 Monitoring for internal corrosion.

(a) Identify critical low spots and instrument the pipeline to monitor relevant operating conditions (e.g., temperature, pressure, velocity, dew point) and implement a program to detect and manage short-term upsets.

(b) Install direct corrosion monitoring at points on the pipeline with significant potential for internal corrosion and implement a program for scheduled monitoring and analysis. For monitoring guidelines, see NACE 3T199, "Techniques for Monitoring Corrosion and Related Parameters in Field Applications."

(c) Implement a liquid water sampling and analysis program, and other indirect monitoring, to determine if there is a significant potential for internal corrosion. If liquid water is present in the system, analysis for CO2, H2S, bacteria (MIC), acids, and other corrosion constituents should be made. See NACE SP0106 and NACE 3T199 for monitoring guidelines.

(d) Use in-line inspection (ILI) tools with a frequency based on corrosion rates and remaining wall thickness, similar to the requirements of an operator's IMP. See NACE SP0102, "In-Line Inspection of Pipelines," regarding design considerations for ILI.

(e) See NACE SP0106, Sections 4, 6, and 7 for operating and maintenance of internal control systems.

4 CHANGE IN CONFIGURATION

(a) The preamble to the initial regulation states that the "change in configuration" means changes in the physical features of a pipeline.

(b) The following are examples of changes to configuration.
   (1) A physical change that would compromise the effectiveness of liquid water removal features downstream, such as the following.
      (i) Reversing flow.
      (ii) Removal of drips, launchers, receivers, or associated piping, valves, or vessels.
      (iii) Diameter changes.
      (iv) Installation of sharp radius bends, or other changes that would make a piggable line no longer piggable.
      (v) Bypassing drips, slug catchers, or filters.
   (2) Adding potential sources of liquid water to the system that would change existing downstream monitoring locations.
   (3) Abandonment or inactivation of a segment of pipeline.
   (4) Changes that would affect existing downstream internal corrosion mitigation systems by changing volume or flow characteristics (e.g., extending the length of a pipeline, changing the diameter over a significant length).
   (5) Changes of material (e.g., replacement of steel pipe with stainless steel pipe).
   (6) Other physical changes that would indicate a change in monitoring or internal corrosion mitigation in downstream facilities.

(c) If a configuration change occurs that increases the risk of internal corrosion, see 3.1 through 3.3.

5 RECORDS

5.1 Design features.

(a) Documentation that the pipeline design features have addressed the impact of internal corrosion may be provided in the operator's project scope, design specifications, standards, or other documents deemed appropriate by the operator.
(b) Documentation that construction of these design features may be provided in the as-built records, which show that the project scope, design specifications, standards, or other applicable documents were followed.
(c) Records may be maintained electronically, as paper copies, or in any other appropriate format.

5.2 Configuration.

Where the operator has determined that the designed pipeline configuration is such that the risk of liquid water collecting is minimal (e.g., internal corrosion is unlikely to occur), the operator is required to document this determination and that the configuration was constructed as designed (see §192.476(d)). For example, if the pipeline diameter was designed so that the gas velocity is such that liquid water will not fall out of the gas stream, documents showing the determination that liquid water will not fall out and the designed pipe diameter was actually installed are necessary.

5.3 Liquid removal features.

Where the operator has determined that liquid water removal features are necessary, the operator will need to document this determination and that the features were installed (see §192.476(d)). For example, if the use of drips is determined to be necessary, the operator needs to document that determination and the related installation. The operator should document the location of each drip installed and the maintenance program for each drip.

5.4 Monitoring devices.

Where the operator has determined that monitoring is necessary at locations with significant potential for internal corrosion, the operator will need to document this determination and that the devices were installed (see §192.476(d)). The operator should also document the following.

(a) Location of equipment.
(b) Sampling protocols.
(c) Procedures for managing upsets.
(d) Calibration process and intervals.

5.5 Documenting impracticable or unnecessary.

The operator is required to document when a design feature is impracticable or unnecessary (see §192.476(d)). The documentation would discuss reasons why it was impracticable or unnecessary to meet the specified design or construction requirements. This documentation may be filed in the operator's design or as-built record system.

5.6 Changes to configuration.

When changing the configuration of a transmission line, the operator is required to document the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line (see §192.476(d)). This documentation may be filed in the operator's design or as-built record system. See 5.3 and 5.4 above.

5.7 Retention.

Records should be kept as long as the pipeline remains in service.

6 REFERENCES

(a) NACE SP0102 (formerly RP0102), "In-Line Inspection of Pipelines."
(b) NACE SP0106, "Control of Internal Corrosion in Steel Pipelines and Piping Systems."
(c) NACE SP0206, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)."
(d) NACE 3T199, "Techniques for Monitoring Corrosion and Related Parameters in Field Applications."
(e) Guide Material Appendix G-192-14.

§192.477

Internal corrosion control: Monitoring.

[Effective Date: 09/05/78]

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]

GUIDE MATERIAL

(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.

(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.

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

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

§192.479

Atmospheric corrosion control: General.

[Effective Date: 10/15/03]

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.
(b) Coating material must be suitable for the prevention of atmospheric corrosion.
(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—
(1) Only be a light surface oxide; or