(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 tools with a frequency based on corrosion rates and remaining wall thickness, similar to the requirements of an operator's IMP. See NACE RP0102, "In-Line Inspection of Pipelines," regarding design considerations for in-line inspection.
(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 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 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."

§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

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

1 GENERAL

(a) The need for coating can be determined by experience in the same or essentially identical environment.
(b) The degree of surface preparation, the selection of the coating materials, and the application procedures must be selected to achieve the desired coating system life span. A reference is the SSPC Painting Manual ("Good Painting Practice" - Volume 1; and "Systems and Specifications" - Volume 2), which is published by the Steel Structures Painting Council.
(c) See guide material under §192.481 for determining areas of atmospheric corrosion.

2 EXPOSED PIPING AND RELATED FACILITIES

The following methods should be considered for exposed piping and related facilities.
(a) Use of coating. See 1 above.
(b) Selection of corrosion resistant materials.
(c) Avoidance of areas where prevailing winds or other conditions will deposit corrosive materials (such as salt, moisture, or industrial effluent). Protection in these areas can be provided by selecting a more appropriate meter and regulator location or by using a protective housing.

(d) Use of materials or coatings or both suitable for the environment may be required for facilities installed in pits, vaults, or casings and that may be periodically submerged or exposed to excessive condensation.
(e) Protection of regulator vent lines from plugging by corrosion products. Where practical, the vent line should be installed in a self-drain position and, where necessary, extended above possible flood level.
(f) Use of material for vent tubing that is compatible with the environment encountered. For example, some kinds of plastic tubing should not be exposed to direct sunlight, and certain aluminum alloys should not be submerged or placed in contact with concrete.

§192.481

Atmospheric corrosion control: Monitoring.

[Effective Date: 10/15/03]

(a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	**Then the frequency of inspection is:**
Onshore	**At least once every 3 calendar years, but with intervals not exceeding 39 months**
Offshore	**At least once each calendar year, but with intervals not exceeding 15 months**

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by §192.479.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

DETERMINING AREAS OF ATMOSPHERIC CORROSION

(a) The presence of atmospheric corrosion can be detected best by visual inspection.
(1) This may require ladders, scaffolds, hoists, or other suitable means of permitting inspector access to the structure being inspected. In addition to the locations listed in §192.481(b), attention should be given to locations such as clamps, rest plates, and sleeved openings.
(2) Piping that is thermally or acoustically insulated (jacketed) should be inspected wherever practical. To minimize damage to the insulation, a visual inspection of the pipe may be performed by cutting windows into the insulation.

(b) Exposure test racks can be used to evaluate coatings and materials in local environments such as industrial, coastal, and offshore locations. Many standard procedures or test methods for evaluating materials and coatings are available from the ASTM International.

(c) Evidence of atmospheric corrosion on meters and regulators may also be determined by inspection by operator employees such as meter readers and leak survey personnel.

§192.483

Remedial measures: General.

[Effective Date: 08/01/71]

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of §192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

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

GUIDE MATERIAL

No guide material necessary.

§192.485

Remedial measures: Transmission lines.

[Effective Date: 01/13/00]

(a) *General corrosion*. Each segment of transmission line pipe with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting*. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

[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. 192-88, 64 FR 69660, Dec. 14, 1999]

GUIDE MATERIAL

1 EVALUATION

1.1 Introduction.
The evaluation of the pressure strength of a corroded region in a transmission pipeline to determine its suitability for continued service can be made by an analytical method, by pressure testing, or by an alternate method.

1.2 Pressure testing.
The pipe containing the corroded region may be pressure tested to confirm the established MAOP, or to determine a lower MAOP. The pressure test should be in accordance with the general requirements of Subpart J (in particular §192.503), and the pressure should be held for at least 8 hours. The established MAOP may be confirmed by testing to a pressure at least equal to the MAOP times the appropriate factor in Table 192.485i or ii below. A lower MAOP may be established by dividing the successful test pressure by the appropriate factor.

(a) For pipeline segments that have not been confirmed for operation in the next higher class location, see §192.611:

CLASS LOCATION	FACTOR
Class 1 locations No buildings for human occupancy within 300 feet	1.10
With buildings for human occupancy within 300 feet	1.25
Class 2 locations	1.25
Class 3 & 4 locations and Meter & Compressor Station piping in Class 1 & 2 locations	1.5

TABLE 192.485i

(b) For pipeline segments that are required to be qualified for an existing class location, see §192.611:

CLASS LOCATION	FACTOR
Class 2	1.25
Class 3	1.50
Class 4	1.80

TABLE 192.485ii

1.3 *Alternate Method*.

For conditions of low stress level, the following method may be used. An MAOP, not to exceed the established MAOP, may be determined by the following formula:

$$P = \frac{2St_rT}{D}$$

Where:

P	=	MAOP (not to exceed established MAOP), psig
S	=	Hoop stress, psig
t_r	=	Actual remaining wall thickness at point of deepest corrosion, inches
T	=	Temperature derating factor, see §192.115
D	=	Nominal outside diameter (see Table 192.105i), inches

S must not exceed 72 percent of SMYS in Class 1 locations, 60 percent in Class 2 locations, 50 percent in Class 3 locations, and 40 percent in Class 4 locations.

2 REPAIR OR REPLACEMENT

If a pipeline has an area of external corrosion that disqualifies it for service at the established MAOP, or if the MAOP cannot be reduced to the indicated safe level, it should be repaired or replaced. For acceptable methods of repair, see 3 below and §§192.703, 192.711(b), 192.713, and 192.717.

3 RELIABLE ENGINEERING TESTS AND ANALYSES (§192.485(a))

Reliable engineering tests and analyses demonstrate compliance with a performance standard. Operators may conduct their own tests and analyses; or, they may choose to accept testing and analyses done by manufacturers, trade associations, consultants, or other operators. The engineering tests and analyses should:

(a) Include the following items, as needed, to achieve satisfactory precision.
  (1) Concise and orderly procedures for conducting tests and analyses.
  (2) Listing of equipment needed.
  (3) Descriptions of test specimens.
  (4) Required calculations.
(b) Exhibit sound engineering practices, which may include the following.
  (1) Knowledge and experience relating to the subject area.
  (2) Data evaluation and statistical analysis.
  (3) Assessment of test results to verify an analytical model.
  (4) Application of scientific principles.

§192.487

Remedial measures: Distribution lines other than cast iron or ductile iron lines.

[Effective Date: 01/13/00]

(a) *General corrosion*. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting*. Except for cast iron or ductile iron pipe, each segment of

distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999]

GUIDE MATERIAL

1 Pitting

Where inspection indicates that pitting exists which may result in leakage, the operator should consider the following.

(a) Examining the corrosion history and leak records to see if the additional information from this examination warrants replacement of a segment of this distribution pipe.
(b) Installing leak clamps on or over the pits.
(c) Cleaning and coating the exposed piping in accordance with §192.461.
(d) Applying cathodic protection (CP).
(e) Installing test wires for monitoring CP.

2 RELIABLE ENGINEERING TESTS AND ANALYSES

See guide material under §192.485.

§192.489
Remedial measures: Cast iron and ductile iron pipelines.

[Effective Date: 08/01/71]

(a) *General graphitization*. Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.
(b) *Localized graphitization*. Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

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

GUIDE MATERIAL

(a) For cast iron pipe, see Guide Material Appendix G-192-18.

(b) For ductile iron, see 5.3(b) of Guide Material Appendix G-192-18.

§192.490

Direct assessment.

[Effective Date: 11/25/05]

Each operator that uses direct assessment as defined in §192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard[1]
External corrosion	§192.925[2]
Internal corrosion in pipelines that transport dry gas	§192.927
Stress corrosion cracking	§192.929

[1]For lines not subject to Subpart O of this part, the terms "covered segment" and "covered pipeline segment" in §§192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.

[2]In §192.925(b), the provision regarding detection of coating damage applies only to pipelines subject to Subpart O of this part.

[Issued by Amdt. 192-101, 70 FR 61571, Oct. 25, 2005]

GUIDE MATERIAL

No guide material available at present.

§192.491

Corrosion control records.

[Effective Date: 07/08/96]

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that

records related to §§192.465(a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

[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]

GUIDE MATERIAL

In addition to the specific requirements of §192.491, the data contained in the records or maps used for corrosion control should include the following.

(a) Location of test stations.
(b) Location of rectifiers and groundbeds.
(c) Location of galvanic anodes.
(d) Location of corrosion control facilities, such as insulating flanges or connections, bonds, automatic switches, and diodes.
(e) Readings of pipe-to-soil potential.
(f) Length and location of cathodically protected segments of piping.
(g) Location of unprotected metallic piping.
(h) Date cathodic protection facilities placed in service.