Part 192 Corrosion Enforcement Guidance

Introduction

The materials contained in this document consist of guidance, techniques, procedures and other information for internal use by the PHMSA pipeline safety enforcement staff. This guidance document describes the practices used by PHMSA pipeline safety investigators and other enforcement personnel in undertaking their compliance, inspection, and enforcement activities. This document is U.S. Government property and is to be used in conjunction with official duties.

The Federal pipeline safety regulations (49 CFR Parts 190-199) discussed in this guidance document contains legally binding requirements. This document is not a regulation and creates no new legal obligations. The regulation is controlling. The materials in this document are explanatory in nature and reflect PHMSA's current application of the regulations in effect at the time of the issuance of the guidance. In preparing an enforcement action alleging a probable violation, an allegation must always be based on the failure to take a required action (or taking a prohibited action) that is set forth directly in the language of the regulation. An allegation should never be drafted in a manner that says the operator "violated the guidance."

Nothing in this guidance document is intended to diminish or otherwise affect the authority of PHMSA to carry out its statutory, regulatory or other official functions or to commit PHMSA to taking any action that is subject to its discretion. Nothing in this document is intended to and does not create any legal or equitable right or benefit, substantive or procedural, enforceable at law by any person or organization against PHMSA, its personnel, State agencies or officers carrying out programs authorized under Federal law.

Decisions about specific investigations and enforcement cases are made according to the specific facts and circumstances at hand. Investigations and compliance determinations often require careful legal and technical analysis of complicated issues. Although this guidance document serves as a reference for the staff responsible for investigations and enforcement, no set of procedures or policies can replace the need for active and ongoing consultation with supervisors, colleagues, and the Office of Chief Counsel in enforcement matters.

Comments and suggestions for future changes and additions to this guidance document are invited and should be forwarded to your supervisor.

The materials in this guidance document may be modified or revoked without prior notice by PHMSA management.

Part 192 Corrosion Enforcement Guidance
Table of Contents
Press <Ctrl><Home> keys to return to TOC

For a complete "Glossary of Terms" please refer to the following link:

http://www.phmsa.dot.gov/staticfiles/PHMSA/Pipeline/TQGlossary/Glossary.html

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.451**
Section Title	**Scope**
Existing Code Language	(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion. (b) [Reserved]
Origin of Code	Authority: Natural Gas Pipeline Act of 1968 (49 U.S.C. sec. 1671 et seq.), Part I regulations of Office of the Secretary of Transportation, 49 CFR Part I, and delegation of authority to Director, Office of Pipeline Safety, 33 FR 16468, unless otherwise noted.
Last Amendment	Amdt. 192–4, 36 FR 12302, June 30, 1971, Amdt. 192–27, 41 FR 34606, Aug.16, 1976; Amdt. 192–33, 43 FR 39389, Sept. 5, 1978
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. Procedures for controlling corrosion are required by §192.13(c) and §192.605(b)(2) including those for the design, installation, operation and maintenance of CP systems. This section, §192.451, states that the procedures are required for external, internal, and atmospheric corrosion control on metallic (steel, aluminum, copper, cast iron, ductile iron, and other metals, as applicable) pipelines. Criteria for CP are contained in Appendix D to Part 192.
Examples of a Probable Violation or Inadequate Procedures	
Examples of Evidence	
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.452(a)**
Section Title	**How does this subpart apply to converted pipelines and regulated onshore gathering lines?**
Existing Code Language	*Converted Pipelines.* Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with §192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.
Origin of Code	NGPSA of 1968
Last Amendment	[Amdt. 192-30, 42 FR 60146, Nov. 25, 1977]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards
Guidance Information	1. First, if the line was substantially in compliance with §192.455 prior to conversion, §192.455 still applies and the CP system must be continuously maintained per the requirements of Subpart I. 2. Second, if the line was not substantially in compliance with §192.455, the line must meet the requirements of §192.457 within 1 year of conversion. 3. Any pipeline segment that is replaced, relocated, or substantially altered must also meet the requirements of §192.455. 4. Note: “Substantially” means that if CP was installed and applied to the pipeline, even though records may not be available to demonstrate that all of the requirements of Subpart I were met, the CP system must be maintained and brought into compliance with all requirements of Subpart I within 1 year.
Examples of a Probable Violation or Inadequate Procedures	1. The operator has a pipeline that was under CP prior to conversion but did not maintain the CP per the requirements of §192.455. 2. The operator has a pipeline that was not under CP prior to conversion and did not install CP within 1 year per the requirements of §192.457. 3. The operator replaced, relocated, or substantially altered a pipeline segment that does not meet the CP requirements of § 192.455.

	Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.
Examples of Evidence	1. Lack of documentation or inadequate field tests and surveys for the pipeline to be converted to determine whether CP substantially met the requirements of §192.455 and to insure that cathodic protection was applied to the pipeline to meet the requirements of Subpart I within 12 months of the conversion. The tests and surveys may include electrical surveys, pipe examination, coating examination, current requirement tests and soil tests. Lack of documentation to demonstrate that the pipeline was evaluated to determine whether CP was required under the provisions of §192.457. Lack of documentation to demonstrate that CP was applied as required by §192.455 to any pipeline segment that was replaced, relocated, or substantially altered.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.452(b)**
Section Title	**How does this subpart apply to converted pipelines and regulated onshore gathering lines?**
Existing Code Language	*Regulated Onshore Gathering Lines.* For any regulated onshore gathering line under §192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under §192.9 after April 14, 2006, because of a change in class location or increase in dwelling density: (1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and (2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.
Origin of Code	NGPSA of 1968
Last Amendment	[Amdt. 192-30, 42 FR 60146, Nov. 25, 1977; Amdt 192-102, 71 FR 13303, Mar. 15, 2006]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. First, If the line was substantially in compliance with §192.455 prior to becoming a regulated onshore gathering line, §192.455 still applies and the CP system must be continuously maintained per the requirements of Subpart I. 2. Second, if the line was not substantially in compliance with §192.455, the line must meet the requirements of 192.457 within 1 year of becoming a regulated onshore gathering line. 3. Note: “Substantially” means that if CP was installed and applied to the pipeline, even though records may not be available to demonstrate that all of the requirements of Subpart I were met, the CP system must be maintained and brought into compliance with all requirements of Subpart I within 1 year.

Examples of a Probable Violation or Inadequate Procedures	1. The operator has a pipeline that was under CP prior to becoming a regulated onshore gathering line but did not maintain the CP per the requirements of 192.455. 2. The operator has a pipeline that was not under CP prior to becoming a regulated onshore gathering line and did not install CP within 1 year per the requirements of 192.457. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Lack of documentation or inadequate field tests and surveys for the pipeline to become a regulated onshore gathering line to determine whether CP substantially met the requirements of §192.455 and to insure that cathodic protection was applied to the pipeline to meet the requirements of Subpart I within 12 months of the conversion. The tests and surveys may include electrical surveys, pipe examination, coating examination, current requirement tests and soil tests. Lack of documentation to demonstrate that the pipeline was evaluated to determine whether CP was required under the provisions of §192.457.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.453**
Section Title	**General**
Existing Code Language	The corrosion control procedures required by §192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.
Origin of Code	NGPSA 1968
Last Amendment	[Amdt. 192-71, 59 FR 6575, Feb. 11, 1994]
Interpretation Summaries	**Interpretation: PI-92-062 Date: November 23, 1992** This interpretation clarifies that an operator is in compliance with § 192.463(a) as long as each point tested under § 192.465(a) meets any one of the Appendix D criteria or its equivalent. If further clarifies that no additional test data are required provided one of the criteria of the Appendix D is met. Lastly, the interpretation clarifies that the operator's corrosion control procedures under § 192.453 should, at a minimum, specify the criterion used for each segment of its pipeline. **Interpretation: PI-ZZ-066 Date: November 3, 1986** Clarifies that Section 192.453 notes that a NACE certification is not specifically required, but would be considered in determining a person's qualifications. Furthermore, this interpretation clarifies that the Department of Transportation does not certify qualified persons. **Interpretation: PI -78-017 Date: June 20, 1978** Clarifies that Section 192.453 acknowledges that some corrosion contractors are not qualified, but that section 192.453 does not regulate such contractors, and the operator is ultimately responsible for compliance with section 192.453 Subpart I regulations. This interpretation also clarifies that the operator must ensure that pipeline activities are carried out by, or under the direction of a person qualified by experience or training in corrosion control methods, in accordance with the requirements of section 192.453. **Interpretation: PI-76-064 Date: September 20, 1976** Clarifies that Section 192.453 requires that the corrosion control activities on any pipeline subject to the Department of Transportation's jurisdiction must be carried out by, or under the direction of a person qualified by experience or training in corrosion control methods. **Interpretation: PI-73-030 Date: October 24, 1973** Clarifies that the activities of section 192.453 contained in Subpart must be carried out by, or under the direction of a person qualified by experience or training in corrosion control methods, but annual reporting of the cathodic protection monitoring is not required by section 192.453.

	Interpretation: PI-73-015 Date: June 22, 1973 Clarifies that the activities of section 192.453 under Subpart I are required to be carried out by, or under the direction of a person qualified by experience or training in corrosion control methods, and that the operator's organizational structure is not relevant to the enforcement of section 192.453.
`Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. The operator must have a written definition of a qualified person, which should include a list of criteria defining what qualifications are required. The description should identify the positions or individuals carrying out or directing the various aspects of the corrosion control program. The qualified person(s) may include contractor personnel. These persons should have knowledge of the physical sciences, principles of engineering and mathematics acquired by education and/or
	practical experience and shall be qualified to engage in the practice of corrosion control, as applicable, for external, internal and atmospheric corrosion. The operator must also specify what documentation is needed to substantiate this qualification. Each operator shall maintain current qualification records for these individuals. 2. Numerous violations and recurring violations of other requirements of this subpart may imply that the person overseeing the corrosion control program is not qualified.

Examples of a Probable Violation or Inadequate Procedures	1. The operator does not have written definition or cannot demonstrate its requirements for the training and level of experience required to be a qualified person or contractor. 2. The operator does not have documentation of the qualified person's training and/or experience. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Position description(s), documentation of training records and/or experience.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.455(a)**
Section Title	**External corrosion control: Buried or submerged pipelines installed after July 31, 1971.**
Existing Code Language	(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following: (1) It must have an external protective coating meeting the requirements of §192.461. (2) It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.
Origin of Code	NGPSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	**Interpretation: PI-ZZ-068 Date: October 13, 1992** Clarifies that language "in its entirety" in Section 192.455 refers to that portion of gathering line jurisdictional to Part 192; and that cathodic protection is not required on those portions of gathering line that are not jurisdictional to the requirements of Subpart I. **Interpretation: PI-77-004 Date: January 19, 1977** Clarifies that operators of natural gas distribution systems with steel pipelines are subject to the requirements of section 192.455 contained in Subpart I. **Interpretation: PI-ZZ-067 Date: August 23, 1974** Clarifies that The regulations at Section 192.455 are correct as written, and that section 192.455 requires cathodic protection on coated and tested steel pipelines. **Interpretation: PI-74-009 Date: February 2, 1974** Clarifies that Section 192.455 requires metallic risers used on plastic service lines be coated and cathodically protected in accordance with Subpart I. **Interpretation: PI-74-003 Date: January 24, 1974** Clarifies that Section 192.455 does not require cathodic protection on above ground pipelines. This interpretation also Clarifies that section 192.455 does not require cathodic protection on a copper pipeline – provided the operator is able to demonstrate by tests, investigation, or experience that cathodic protection is not required. **Interpretation: PI-74-004 Date: January 24, 1974** Clarifies that Section 192.455 requires metallic riser pipes to be coated and cathodically protected in accordance with Subpart I. **Interpretation: PI-73-017 Date: June 25, 1973** Clarifies that Section 192.455 requires that simply coating and wrapping a stainless

	steel or metallic coupling installed in a plastic pipeline does not meet the cathodic protection requirements of Section 192.455 under Subpart I. **Interpretation: PI-71-081 Date: October 14, 1971** Section 192.455 requires that all new metallic pipe must be coated and cathodically protected unless it meets the exceptions in 192.455(b) or 192.455(c).
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. Most pipelines are coated when installed and cathodically protected shortly after completion of construction. "Completion of construction" is generally considered to be when the pipeline or pipeline section has been tested, backfilled, and ready for gas to flow. 2. It is not often that an operator will attempt to install a bare unprotected steel pipeline under §192.455(b), or a copper pipeline under §192.455(c), as it is very difficult to demonstrate that a non-corrosive environment exists around the pipeline. One method of showing that a non-corrosive environment exists is to have external corrosion coupons installed in the right of way that demonstrate no active corrosion.
Examples of a Probable Violation or Inadequate Procedures	1. The operator has a pipeline installed after July 31, 1971, that is not externally coated pursuant to the requirements of § 192.461 and the operator has not demonstrated the absence of a corrosive environment pursuant to §192.455 (b) or (c). 2. The operator has a pipeline installed after July 31,1971, that does not have a cathodic protection system installed within 1 year after completion of construction and the operator has not demonstrated the absence of a corrosive environment pursuant to § 192.455 (b) or (c). *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Documentation showing pipeline installed after July 31, 1971, including but not limited to, operators' records (construction contracts and project reports), or construction permits. 2. Documentation showing that pipeline is not externally coated pursuant to requirements of §192.461, including operators' records showing lack of external coating (construction specifications) and photographs of exposed pipe. 3. Documentation showing that operator does not have a cathodic protection system meeting requirements of subpart I: (I) Operator records kept pursuant to §192.491 as they relate to requirements in §192.463. (ii) Statements of investigator's field observations of operators' random sampling of pipe-to-soil potential measurements and description of testing equipment. 4. Documentation showing pipeline was constructed more than 1 year earlier.
Other Special Notations	

Enforcement Guidance	**CORROSION – Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.455(b)**
Section Title	**External corrosion control: Buried or submerged pipelines installed after July 31, 1971.**
Existing Code Language	(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a) (2) of this section.
Origin of Code	NGPSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. If the pipeline is not externally coated or cathodically protected and the operator has not demonstrated the absence of a corrosive environment, then a violation exists. Note: Within 6 months after an installation made pursuant to §192.455(b) (no coating &/or no CP system), the operator shall conduct tests, including determination of various chemical constituents in the soil environment(chlorides, sulfates, sulfides and bicarbonates); including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet(6 meters), and soil resistivity measurements at potential profile peak locations. 2. Operator must plot the close interval survey (CIS) to identify peak locations in which to take soil resistivity measurements to adequately evaluate the potential profile along the entire pipeline. Measurements must be taken to determine soil resistivity at the depth of the pipe. If the tests made indicate that a corrosive condition exists (areas with lower soil resistivity in areas of more negative potentials or areas where chemical constituents are present which may indicate a propensity for aerobic or anaerobic bacterial corrosion), the pipeline must be cathodically protected in accordance with paragraph §192.455(a)(2). If tests indicate that a corrosive condition does not exist (areas of high resistivity soil in areas with less negative potentials), the operator must follow the requirements of §192.465(e).

Examples of a Probable Violation or Inadequate Procedures	1. The operator has not demonstrated the absence of a corrosive environment and the pipe is not externally coated or cathodically protected. 2. The operator did not conduct tests within 6 months after an installation. 3. The tests do not include pipe-to-soil potential and soil resistivity measurements at potential profile peak locations as required. 4. The violation cited will most likely be of § 192.455(a) rather than § 192.455(b). *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Lack of documentation or inadequate demonstration of absence of corrosive environment by operator, including a copy of and an analysis of operators' records of tests, which must include soil resistivity measurements, tests for corrosion accelerating bacteria, and, within 6 months after installation, pipe-to-soil potential measurements and soil resistivity measurements at potential profile peak locations as specified in §192.455(b).
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.455(c)**
Section Title	**External corrosion control: Buried or submerged pipelines installed after July 31, 1971.**
Existing Code Language	(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that – (1) For a copper pipeline, a corrosive environment does not exist, or (2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.
Origin of Code	NGPSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	
Advisory Bulletin/Alert Notices Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	
Examples of a Probable Violation or Inadequate Procedures	1.The pipeline is copper and the operator has not demonstrated the absence of a corrosive environment; or 2. The pipeline is temporary with an intended service life not to exceed 5 years and the operator did not demonstrate that corrosion which might occur within that period is not detrimental to public safety; or 3. The violation cited will most likely be of § 192.455(a) rather than § 192.455(c). *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Corrosion control design and construction specifications showing the operator installed a copper line without cathodic protection. Statement from inspector concerning actual witnessing CP readings that indicate inadequate cathodic protection and leak history. The operator's records state that a pipeline is a temporary pipeline (service life not to exceed 5 years) and the line has been in service beyond the 5 years, or corrosion occurring during the 5 year service life of the pipeline would be detrimental to public safety.
Other Special Notations	The criteria for the cathodic protection of copper are different than those for steel and are contained in Part 192, Appendix D.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.455(d)**
Section Title	**External corrosion control: Buried or submerged pipelines installed after July 31, 1971.**
Existing Code Language	Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a)(2) of this section.
Origin of Code	NGPSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	
Examples of a Probable Violation or Inadequate Procedures	1. The operator has a pipeline that is coated but not cathodically protected within 1 year of construction. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Construction records and dates of initial CP readings.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.455(e)**
Section Title	**External corrosion control: Buried or submerged pipelines installed after July 31, 1971.**
Existing Code Language	Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.
Origin of Code	NGPSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	
Examples of a Probable Violation or Inadequate Procedures	1. The operator has a pipeline that is aluminum, the soil Ph is >8 and the operator has not performed tests or does not have documented experience indicating suitability in that particular environment. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Lack of documentation that appropriate tests were made to determine pH of the soil along the entire pipeline right-of-way (ROW). 2. Lack of documentation showing tests/experience indicating suitability in an environment where Ph is greater than 8.i 3. Review of documentation that the operator performed appropriate tests and incorrectly applied the findings.
Other Special Notations	This will be an unusual situation.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.455(f)**
Section Title	**External corrosion control: Buried or submerged pipelines installed after July 31, 1971.**
Existing Code Language	This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if: (1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition, and (2)The fitting is designed to prevent leakage caused by localized corrosion pitting.
Origin of Code	NGPSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	
Examples of a Probable Violation or Inadequate Procedures	1. The operator has a plastic pipeline with isolated metal alloy fittings that are not cathodically protected and the operator cannot show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition. 2. The operator has a plastic pipeline with isolated metal alloy fittings that are not designed to prevent leakage caused by local corrosion pitting. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Lack of documentation or inadequate demonstration of tests, investigation or experience to show that electrically isolated metal alloy fittings in plastic pipelines are protected from corrosion.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.457(a)**
Section Title	**External corrosion control: Buried or submerged pipelines installed before August 1, 1971.**
Existing Code Language	Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.
Origin of Code	NGPSA 1968
Last Amendment	[Amdt. 192-4, 36 FR 12297, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]
Interpretation Summaries	**Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-89-003 Date: March 31, 1989** This interpretation clarifies that if an operator voluntarily places a cathodic protection system on a gas pipeline installed prior to August 1, 1971, with no evidence of active corrosion, the operator should assure that their program properly addressed all the requirements of the regulations, such as using the definition of active corrosion under §192.457(c). The interpretation also clarifies that in determining whether the electrical survey required by §192.457(b)(3) and §192.465(e) is impractical, the operator must consider all factors that relate to the impracticality, including public safety. **Interpretation: PI-74-003 Date: January 24, 1974** Clarifies that Section 192.457 does not require cathodic protection on above ground pipelines. This interpretation also Clarifies that section 192.457 does not require cathodic protection on a copper pipeline – provided the operator is able to demonstrate by tests, investigation, or experience that cathodic protection is not required.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary

Guidance Information	1. Effectively coated pipelines require much less cathodic protection current than those that are bare or poorly coated. Bare pipe typically requires 1-2 mA/sq ft. For a well-coated pipeline, the effectiveness of the coating may be as high as 99% or greater, which would reduce the current requirement by a corresponding amount. If the operator chooses to treat a poorly coated pipeline as if it were bare, the testing and monitoring requirements are greatly reduced. Bare lines are required to be electrically monitored by hot spot or cell-to-cell survey on a three (3) year cycle rather than on an annual basis. (NOTE: A hot spot or cell-to-cell survey measures earth current gradients and is not an electrical survey as defined in 192.465(e)(2) as a pipe-to-soil potential survey, since there is no electrical connection to the pipeline.) 2. Obviously, the line is not cathodically protected if the line is experiencing corrosion leaks. If corrosion leaks have occurred, the operator should be prepared to demonstrate that the CP system has been re-evaluated and additional measures taken to correct any shortcomings. These include but are not limited to: installing additional test wires; additional anodes; increasing the output of the rectifier; a close interval survey to determine areas of inadequate protection, etc.
Examples of a Probable Violation or Inadequate Procedures	1. The operator has a transmission pipeline, other than buried piping at compressor, regulator, or measuring stations, installed before August 1, 1971, that has an effective external coating and is not cathodically protected. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Documentation showing pipeline is not at a compressor, regulator, or measuring station, including photographs, operators' records, etc.; and documentation that the line does have an effective coating (operators' inspection and maintenance records, construction records, etc.). If the operator claims that the coating is ineffective, the operator is required to have documentation to show that its cathodic protection current requirements are substantially the same as if it were a bare pipeline. Also, documentation showing pipeline is not cathodically protected pursuant to Subpart I along entire area that is effectively coated.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.457(b)**
Section Title	**External corrosion control: Buried or submerged pipelines installed before August 1, 1971.**
Existing Code Language	Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found: (1) Bare or ineffectively coated transmission lines. (2) Bare or coated pipes at compressor, regulator, and measuring stations. (3) Bare or coated distribution line.
Origin of Code	NGPSA 1968
Last Amendment	[Amdt. 192-4, 36 FR 12297, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39389, Sept. 5, 1978], Amdt. 192-93, 68 FR 53895, Sept. 15, 2003
Interpretation Summaries	**Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-89-003 Date: March 31, 1989** This interpretation clarifies that if an operator voluntarily places a cathodic protection system on a gas pipeline installed prior to August 1, 1971, with no evidence of active corrosion, the operator should assure that their program properly addressed all the requirements of the regulations, such as using the definition of active corrosion under §192.457(c). The interpretation also clarifies that in determining whether the electrical survey required by §192.457(b)(3) and §192.465(e) is impractical, the operator must consider all factors that relate to the impracticality, including public safety. **Interpretation: PI-74-003 Date: January 24, 1974** Clarifies that Section 192.457 does not require cathodic protection on above ground pipelines. This interpretation also Clarifies that section 192.457 does not require cathodic protection on a copper pipeline – provided the operator is able to demonstrate by tests, investigation, or experience that cathodic protection is not required.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary

Guidance Information	1. Determine the method the operator used to locate areas of active corrosion on its bare or ineffectively coated sections of pipeline. Examine the performance of electrical surveys, and their practicality. Study corrosion and leak history records, in-line inspection records, and other sources of information on potential corrosion. Look for areas of active corrosion. Active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety. 2. Bare lines are required to be electrically monitored by hot spot or cell-to-cell survey on a three (3) year cycle rather than on an annual basis. (NOTE: A hot spot or cell-to-cell survey measures earth current gradients and is not an electrical survey as defined in 192.465(e)(2) as a pipe-to-soil potential survey, since there is no electrical connection to the pipeline.) 3. ***City of Danville [1-2002-0004]*** **(Sept. 5, 2002)** – Found that the operator failed to evaluate its cathodically unprotected bare and coated steel piping for active corrosion, where the operator said it performed a leak survey every three years but could not provide records to show that leak surveys were actually used to identify areas of active corrosion. While the regulations provide for the use of alternative methods to identify corrosion when electrical surveys are impractical, OPS guidelines recommend that such leak surveys done in lieu of electrical testing be conducted at least once per year because leak surveys identify corrosion only after leaking begins. CO, CP
Examples of a Probable Violation or Inadequate Procedures	1. The operator has a bare or ineffectively coated transmission line, a bare or coated pipe in a compressor, regulator, or measuring station, or a bare or coated distribution line but has not determined areas of active corrosion by data obtained from electrical survey, in-line inspection, corrosion leak history, corrosion surveys etc. The operator has not cathodically protected the pipeline where areas of active corrosion were found. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Documentation including photographs, operators' records, etc., showing pipeline was installed before August 1, 1971; showing pipeline is not cathodically protected; and that the pipeline is bare (operator's inspection and maintenance records, construction records, etc.). 2. If the operator claims that the coating is ineffective, documentation that its cathodic protection current requirements are substantially the same as if it were a bare pipeline. Include a copy of documentation and your analysis of operators' records of tests to determine current requirements, records per § 192.491; or 3. Lack of documentation which would verify that an operator has attempted to locate areas of active corrosion and to cathodically protect areas of active corrosion. Include any operator statements to this effect; or documentation that an operator has active corrosion on its pipeline (see Appendix D), and documentation which shows that programs initiated by an operator to cathodically protect or replace the pipeline in areas of active corrosion is inadequate, i.e., operator is unable to demonstrate that the areas of active corrosion were mitigated; or

	4. Lack of documentation to show that an operator has taken action to mitigate areas of active corrosion, which were located by electrical surveys or other special studies performed by the operator. See §192.455(2)(b).
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.459**
Section Title	**External corrosion control: Examination of buried pipeline when exposed.**
Existing Code Language	Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under Sections 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.
Origin of Code	NGPSA 1968
Last Amendment	[Amdt. 192-4, 36 FR 12297, June 30, 1971, as amended by Amdt. 192-87, 64 FR 56978, Oct. 22, 1999]
Interpretation Summaries	**Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489**.**
Advisory Bulletin/Alert Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator should have this procedure spelled out in its manual and be able to demonstrate that its procedure is carried out. 2. There is an issue of how far to carry an investigation of harmful corrosion found at an excavation. The operator should be concerned that harmful corrosion located near the exposed portion of pipe would go undetected if operators investigated only for corrosion that adjoins corrosion observed on the exposed portion. However, recognizing the complexity of specifying the scope of investigation, the regulation allows operators to use their own judgment on where to stop investigating for corrosion. In conclusion, a reasonable effort should be required to find corrosion in the vicinity of an exposed, corroded pipe. 3. If deteriorated or disbonded coating or external corrosion is found, the operator shall continue to investigate circumferentially and longitudinally until corrosion or damaged or disbonded coating requiring remedial action are no longer encountered.
Examples of a Probable Violation or Inadequate	1. The operator's pipe was exposed but was not examined for evidence of external corrosion. 2. If external corrosion requiring remedial action under 192.483 through 192.489 was found, and the operator did not investigate circumferentially and longitudinally

Procedures	beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Documentation of a pipeline exposure, the examination, pictures, maintenance records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.461(a)**
Section Title	**External corrosion control: Protective coating.**
Existing Code Language	Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must- (1) Be applied on a properly prepared surface; (2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture; (3) Be sufficiently ductile to resist cracking; (4) Have sufficient strength to resist damage due to handling and soil stress; and; (5) Have properties compatible with any supplemental cathodic protection.
Origin of Code	NGPSA 1968
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator's procedures or specifications should require the use of a material designed for application to prevent corrosion of buried or submerged metallic structures, including pipelines. 2. Procedures for surface preparation and application should be consistent with manufacturer's recommendations and applicable industry standards.
Examples of a Probable Violation or Inadequate Procedures	1. The operator does not have procedures regarding the selection of a proper coating. 2. The operator has utilized a coating that does not have the required properties. 3. The surface of the pipeline was not prepared in accordance with the application procedures. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Manufacturer's maintenance recommendations, O&M Manual, maintenance records, pictures. Pictures of areas of disbonded coating on relatively newly coated or recoated pipe.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.461(b)**
Section Title	**External corrosion control: Protective coating.**
Existing Code Language	Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.
Origin of Code	NGPSA 1968
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator's procedures or specifications should require the use of a material designed for application to prevent corrosion of buried or submerged metallic structures, including pipelines.
Examples of a Probable Violation or Inadequate Procedures	1. The operator does not have procedures regarding the selection of a proper coating. 2. The operator has utilized a coating that does not have the required moisture absorption and insulating properties. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operators purchase specifications, manufacturer's literature, O&M Manual, maintenance records, pictures.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.461(c)**
Section Title	**External corrosion control: Protective coating.**
Existing Code Language	Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.
Origin of Code	NGPSA 1968
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	Electrical testing is commonly known as "jeeping." The voltage utilized for the electrical testing must be in accordance with the manufacturer's recommendations or applicable industry standards. The voltage may vary with coating thickness and type; such as over girth welds, fittings, or coating repairs. Coating material damaged or improperly installed must be repaired.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not inspect the coating prior to lowering the pipeline into the ditch or submerging the pipe. 2. The operator did not repair coating damage discovered during an inspection. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Manufacturer(s)' inspection recommendations, O&M Manual, installation records, pictures.
Other Special Notations	Jeeping is an electrical inspection, and is typically performed during construction.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.461(d)**
Section Title	**External corrosion control: Protective coating.**
Existing Code Language	Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.
Origin of Code	NGPSA 1968
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator must protect the coating from damage as it is being lifted, installed into the ditch, and backfilled. The operator should maintain applicable procedures that address areas such as the type of fabric slings with stringers that will be used to lift and place the pipe in the ditch; how the pipe is protected from rocks in the backfill, etc. The operator's procedures should also address protection of the pipeline in the ditch, backfilling, and ditch padding. Supporting blocks used during construction should be spaced so as to prevent damage to the coating where the blocks support the pipe. Supporting blocks should not remain under the pipeline when it is backfilled.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not protect the external coating from damage due to adverse ditch conditions or damage from supporting blocks. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's O&M manual, pictures, inspection documentation records, field notes.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.461(e)**
Section Title	**External corrosion control: Protective coating.**
Existing Code Language	If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.
Origin of Code	NGPSA 1968
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	The operator should have developed procedures for taking precautions to protect the coating while installing pipe in such a manner. Some operators may elect to install an abrasion-resistant coating, such as various concrete materials, over the dielectric coating used for the cathodic protection. The operator should utilize an appropriate bore size/diameter ratio and a sufficient bend radius to minimize potential damage to the coating (and possibly to the pipe). The operator should also inspect for damage on the pipe visible in the bore's exit pit. Damage noted to the coating and/or pipe in the exit pit might indicate that additional undetected damage may have occurred during the installation to the coating and/or the pipe that is not visible. Note if the operator doing any type of testing on the carrier pipe after boring or pulling to determine the effectiveness of the coating as a dielectric between the casing or soil.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not take precautions to minimize damage to the coating during installation by pulling, boring, or other similar methods or did not inspect for potential coating damage. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Manufacturer's maintenance recommendations, O&M Manual, maintenance records, pictures. Missing or incomplete records of taking the appropriate precautions, inspecting the installed pipe, and/or repairing damage to the pipe coating.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.463(a)**
Section Title	**External corrosion control: Cathodic protection.**
Existing Code Language	(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.
Origin of Code	NGPLSA 1968
Last Amendment	
Interpretation Summaries	**Interpretation: PI-ZZ-069 Date: November 9, 2005** This interpretation of section 192.465 clarifies the definition of the term "separately protected service lines" to mean a buried or submerged service line that is electrically isolated and cathodically protected from other metallic structures. The interpretation also explains that separate steel service risers that are electrically interconnected and cathodically protected by a common source are not separately protected lines; and that therefore, §192.465(a) requires an operator to monitor such pipelines at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. **Interpretation: PI-93-0390 Date: July 16, 1993** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-92-062 Date: November 23, 1992** This interpretation clarifies that an operator is in compliance with § 192.463(a) as long as each point tested under § 192.465(a) meets any one of the Appendix D criteria or its equivalent. If further clarifies that no additional test data are required provided one of the criteria of the Appendix D is met. Lastly, the interpretation clarifies that the operator's corrosion control procedures under § 192.453 should, at a minimum, specify the criterion used for each segment of its pipeline. **Interpretation: PI-91-032 Date: November 7, 1991** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring

	equipment) provides reliable data. **Interpretation: PI-91-025 Date: August 29, 1991** This interpretation clarifies that Appendix D, Part II, Part 192 of Title 49, is clear that voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of voltage measurements. **Interpretation: PI-89-003 Date: March 31, 1989** This interpretation clarifies that if an operator voluntarily places a cathodic protection system on a gas pipeline installed prior to August 1, 1971, with no evidence of active corrosion, the operator should assure that their program properly addressed all the requirements of the regulations, such as using the definition of active corrosion under §192.457(c). The interpretation also clarifies that in determining whether the electrical survey required by §192.457(b)(3) and §192.465(e) is impractical, the operator must consider all factors that relate to the impracticality, including public safety.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	The operator is required to meet one of the criteria in Appendix D. **Special Conditions:** 1. In some situations, such as the presence of sulfides, bacteria, elevated temperatures, acid environments and dissimilar metals, the criteria may not be sufficient. 2. Caution is advised against using polarized potentials less negative than -850mv for cathodic protection of pipelines when operating pressures and conditions are conducive to stress corrosion cracking, e.g. elevated temperatures (>100 degrees F). 3. The use of excessive polarized potentials, more negative than approximately -1200mV, on some coated pipelines should be avoided to minimize disbondment of the coating. (The amount of CP current required is directly proportional to the quality and integrity of the coating.) 4. Excessive impressed CP may result in the generation of hydrogen which may cause (hydrogen) embrittlement of steel structures. (Particularly in higher strength steel as specified for API-5L grade X70 and higher pipe and in older steel pipe with hard spots). 5. Uniform methods for determining voltage drops and polarization shall be selected. Once voltage drop(s) (IR Drops), polarized potentials, and/or polarization have been determined, they may be used for correcting future potential measurements at the same location, providing conditions such as pipe and cathodic protection system operating conditions, soil characteristics and conditions, and external coating quality remain similar. 6. The preferred method to compensate for IR drop errors is to measure the structure- to-electrolyte potential immediately upon simultaneous interruption of all current sources. When it is impractical to disconnect all current sources to correct for voltage drop(s), sound engineering practices should be used to ensure that adequate cathodic protection has been achieved. This may be the case for galvanic systems.

	7. The use of in-line inspection data is not sufficient to demonstrate compliance with any of the cathodic protection criteria. 8. Situations may exist where a single criterion for evaluating the effectiveness of cathodic protection may not be satisfactory for all conditions. 9. The criterion for determining cathodic protection levels for each pipeline or pipeline segment shall be identified. 10. If the line is experiencing corrosion leaks it is the operator's responsibility under section 192.471 to provide sufficient test stations on their entire protected system to determine the adequacy of the criteria used. 11. The operator's records should indicate what criterion the operator is using. For offshore pipelines and other applications that might utilize an alternate to the copper-copper sulfate reference electrode, the type of reference electrode should be noted.
Examples of a Probable Violation or Inadequate Procedures	1. The operator's records and field measurements indicate that the cathodic protection system does not provide a level of cathodic protection established by one or more of the applicable criteria in Appendix D of Part 192. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's corrosion control procedures, maintenance records, field measurements by the inspector & verification of low readings, photographs. Documentation that cathodic protection is required for the pipeline at issue, including evidence required to show pipeline must be cathodically protected under §§192.455, 192.457, and 192.483 (i.e., evidence that pipeline was installed after July 31, 1971, and that the operator did not demonstrate the absence of a corrosive environment).
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.463(b)**
Section Title	**External corrosion control: Cathodic protection.**
Existing Code Language	(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential. (1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or (2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D of this part for amphoteric metals.
Origin of Code	NGPLSA 1968
Last Amendment	
Interpretation Summaries	**Interpretation: PI-ZZ-069 Date: November 9, 2005** This interpretation of section 192.465 clarifies the definition of the term "separately protected service lines" to mean a buried or submerged service line that is electrically isolated and cathodically protected from other metallic structures. The interpretation also explains that separate steel service risers that are electrically interconnected and cathodically protected by a common source are not separately protected lines; and that therefore, §192.465(a) requires an operator to monitor such pipelines at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. **Interpretation: PI-93-039 Date: July 16, 1993** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-92-062 Date: November 23, 1992** This interpretation clarifies that an operator is in compliance with § 192.463(a) as long as each point tested under § 192.465(a) meets any one of the Appendix D criteria or its equivalent. If further clarifies that no additional test data are required provided one of the criteria of the Appendix D is met. Lastly, the interpretation clarifies that the operator's corrosion control procedures under § 192.453 should, at a minimum, specify the criterion used for each segment of its pipeline. **Interpretation: PI-91-032 Date: November 7, 1991** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source,

	provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-91-025 Date: August 29, 1991** This interpretation clarifies that Appendix D, Part II, Part 192 of Title 49, is clear that voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of voltage measurements. **Interpretation: PI-89-003 Date: March 31, 1989** This interpretation clarifies that if an operator voluntarily places a cathodic protection system on a gas pipeline installed prior to August 1, 1971, with no evidence of active corrosion, the operator should assure that their program properly addressed all the requirements of the regulations, such as using the definition of active corrosion under §192.457(c). The interpretation also clarifies that in determining whether the electrical survey required by §192.457(b)(3) and §192.465(e) is impractical, the operator must consider all factors that relate to the impracticality, including public safety.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. Amphoteric metals are those that are susceptible to corrosion in both acid and alkaline environments. The following is from Peabody's Control of Pipeline Corrosion second edition page 63-64: 2. "Criterion For Dissimilar Metal Piping SP0169-2007 contains a single criterion for dissimilar metal piping. Under paragraph 6.2.5.1, the following criterion is listed: "A negative voltage between all pipe surfaces and a stable reference electrode contacting the electrolyte equal to that required for the protection of the most anodic metal should be maintained." 3. There is one precautionary note, under Paragraph 6.2.5.2: "Amphoteric materials that could be damaged by high alkalinity created by CP should be electrically isolated and separately protected." Amphoteric metals include aluminum, titanium, and zirconium. In practice, this criterion applies only where carbon steel or cast iron is coupled to a more noble metal such as copper. In this situation, either of the 850 mV criterion would apply: [850 mV (CSE) with the CP applied or a polarized potential of 850 mV (CSE).] Other criteria, such as the 100 mV of polarization criterion would not be applicable."
Examples of a Probable Violation or Inadequate Procedures	1. The amphoteric metals are not electrically isolated from the remainder of the pipeline and not cathodically protected. The operator has not calculated and applied a level of cathodic protection required by one of the applicable criteria in appendix D of Part 192. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Operator's corrosion control procedures, maintenance records, photographs.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.463(c)**
Section Title	**External corrosion control: Cathodic protection.**
Existing Code Language	The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.
Origin of Code	NGPLSA 1968
Last Amendment	
Interpretation Summaries	**Interpretation: PI-ZZ-069 Date: November 9, 2005** This interpretation of section 192.465 clarifies the definition of the term "separately protected service lines" to mean a buried or submerged service line that is electrically isolated and cathodically protected from other metallic structures. The interpretation also explains that separate steel service risers that are electrically interconnected and cathodically protected by a common source are not separately protected lines; and that therefore, §192.465(a) requires an operator to monitor such pipelines at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. **Interpretation: PI-93-039 Date: July 16, 1993** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-92-062 Date: November 23, 1992** This interpretation clarifies that an operator is in compliance with § 192.463(a) as long as each point tested under § 192.465(a) meets any one of the Appendix D criteria or its equivalent. If further clarifies that no additional test data are required provided one of the criteria of the Appendix D is met. Lastly, the interpretation clarifies that the operator's corrosion control procedures under § 192.453 should, at a minimum, specify the criterion used for each segment of its pipeline. **Interpretation: PI-91-032 Date: November 7, 1991** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data.

	Interpretation: PI-91-025 Date: August 29, 1991 This interpretation clarifies that Appendix D, Part II, Part 192 of Title 49, is clear that voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of voltage measurements. **Interpretation: PI-89-003 Date: March 31, 1989** This interpretation clarifies that if an operator voluntarily places a cathodic protection system on a gas pipeline installed prior to August 1, 1971, with no evidence of active corrosion, the operator should assure that their program properly addressed all the requirements of the regulations, such as using the definition of active corrosion under §192.457(c). The interpretation also clarifies that in determining whether the electrical survey required by §192.457(b)(3) and §192.465(e) is impractical, the operator must consider all factors that relate to the impracticality, including public safety.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The use of excessive polarized potentials, more negative than approximately -1200mV, on some coated pipelines may lead to disbondment of the coating. (The amount of CP current required is directly proportional to the quality and integrity of the coating). 2. Excessive impressed CP may result in the generation of hydrogen which may cause (hydrogen) embrittlement of steel structures. (Particularly in higher strength steel as specified for API-5L grade X70 and higher pipe and in older steel pipe with hard spots).
Examples of a Probable Violation or Inadequate Procedures	1. The operator has excessive polarized pipe-to-soil readings that may lead to damage of the coating. The operator has discovered coating deterioration due to excessive cathodic protection current or cracking due to hydrogen embrittlement. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's maintenance records, verification of coating damage by bell hole inspection, photographs.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.465(a)**
Section Title	**External corrosion control: Monitoring**
Existing Code Language	Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	**Interpretation: PI-ZZ-069 Date: November 9, 2005** This interpretation of section 192.465 clarifies the definition of the term "separately protected service lines" to mean a buried or submerged service line that is electrically isolated and cathodically protected from other metallic structures. The interpretation also explains that separate steel service risers that are electrically interconnected and cathodically protected by a common source are not separately protected lines; and that therefore, §192.465(a) requires an operator to monitor such pipelines at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. **Interpretation: PI-93-039 Date: July 16, 1993** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-92-062 Date: November 23, 1992** This interpretation clarifies that an operator is in compliance with § 192.463(a) as long as each point tested under § 192.465(a) meets any one of the Appendix D criteria or its equivalent. If further clarifies that no additional test data are required provided one of the criteria of the Appendix D is met. Lastly, the interpretation clarifies that the operator's corrosion control procedures under § 192.453 should, at a minimum, specify the criterion used for each segment of its pipeline. **Interpretation: PI-ZZ-068 Date: October 13, 1992** Clarifies the applicability of §192.465 to jurisdictional sections of a buried gathering line. Part §192.465 requires cathodically protected jurisdictional sections to be tested once each calendar year, even if the remainder of the gathering line is not

protected. The phrase "in its entirety," as cited in 192.455(a)(2), embraces only pipelines or sections of pipeline which are subject to Part 192. A line does not have to be cathodically protected from end to end if part of the line is non-jurisdictional; only the jurisdictional portion requires cathodic protection.

Interpretation: PI-91-032 Date: November 7, 1991

This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data.

Interpretation: PI-91-025 Date: August 29, 1991

Clarifies that Appendix D, Part II, Part 192, is clear that voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of voltage measurements. When an operator claims they have accounted for IR drop, OPS will accept that claim. If, however, the operator had a leak due to corrosion, OPS may ask the operator to demonstrate the adequacy of corrosion protection and how the operator considered the IR drop and if this was done improperly, the operator could be subject to enforcement action. It is possible to consider the IR drop on magnesium anode protected systems if an inspector or operator places the half cell on the surface of the soil/ground and obtains an abnormally high potential, there is a good possibility that the half cell is over an anode. To ensure that it is not, an inspector or operator should simply move the half cell upstream or downstream from that point and take a reading. OPS does not require operators to disconnect anode wires in order to read instant-off potentials on distributed sacrificial anode protected systems.

Interpretation: PI-ZZ-080 Date: August 19, 1991

Clarifies that an operator has the freedom to conduct its inspections, of rectifiers or other impressed current power sources, utilizing whatever technology or means they choose. The acceptability of electronic data collection and the subsequent broadcast of this data to operators as a means of inspection would depend on the capability to meet §192.465(b) and would also depend on the reliability of the data transmitted to operators. Federal and State field inspectors would review the data to determine its relevance when conducting an inspection.

Interpretation: PI-89-003 Date: March 31, 1989

This interpretation clarifies that if an operator voluntarily places a cathodic protection system on a gas pipeline installed prior to August 1, 1971, with no evidence of active corrosion, the operator should assure that their program properly addressed all the requirements of the regulations, such as using the definition of active corrosion under §192.457(c). The interpretation also clarifies that in determining whether the electrical survey required by §192.457(b)(3) and §192.465(e) is impractical, the operator must consider all factors that relate to the impracticality, including public safety.

Interpretation: PI-85-009 Date: October 24, 1985

Clarifies that permanent potential monitoring test stations, placed throughout a steel gas distribution system which is completely welded (no couplings) and checked on a monthly basis, satisfy the annual "test for cathodic protection" requirement. If an operator tests at sufficient test stations per §192.469 and demonstrates compliance with §192.463, then the testing would also comply with the requirements of §192.465(a).

Interpretation: PI-81-011 Date: May 29, 1981

Clarifies that compliance with 49 CFR 192.465(a), requires cathodically protected pipelines be tested annually to determine if protection is at the levels required by §192.463 and Appendix D to Part 192. The regulations do not require the use of specific testing methods, and any technique may be used that accurately shows the cathodic protection levels. This office does not recommend one test method over another, and our approval is not needed for an operator to use a new method.

Interpretation: PI-ZZ-070 Date: November 15, 1979

#1 Clarifies that Section 192.465(a) requires all pipelines under cathodic protection to be tested at least once each calendar year to determine compliance with §192.463, with the exception of service lines and short sections of protected mains 100 feet or less in length, which may be tested on a sampling basis. Sampling of these short sections must be done so that at least 10% of the total short piping segments within the pipeline system are tested each calendar year. The tests required must determine whether the cathodic protection requirements of §192.463 and Appendix D are being met.

#2 Clarifies that Section 192.465(c) sets monitoring requirements for the effectiveness of equipment installed to prevent damage due to stray currents. Section 192.473(a) requires each operator to minimize the effects of stray currents on its pipeline and (b) minimize the effects of stray currents from its cathodic protection system on existing adjacent underground metallic structures. If stray current from a pipeline cathodic protection system is causing damage to another underground metallic pipeline system or structure (owned by the same operator or others), the operator must minimize the detrimental effects of such currents. “Other interference bonds” as referred to in §192.465(c) are bonds whose failure would not jeopardize structure protection.

#3 Clarifies that §192.473(b) requires both impressed current and galvanic anode cathodic protection systems to be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures. Where an adverse effect is determined to exist on an adjacent underground structure, §192.473(b) would require corrective action. In addition, there may be other legal responsibility for damage done by rectifiers.

#4 Clarifies that compliance with a given requirement is mandatory on and after the effective date. Section 192.465 became effective on August 1, 1971, and §192.473 on July 31, 1973. Service lines subject to Part 192 installed after July 31, 1971, must have had a cathodic protection system in place within 1 year after the line was installed (§192.455). Under §192.457, other service lines were required to be electrically surveyed for areas of active corrosion and cathodically protected in those areas by August 1, 1976.

Interpretation: PI-ZZ-077 Date: August 23, 1978

Clarifies that a rectifier cannot be inspected to ensure that it is operating (Section 192.465, paragraph b) by taking pipe-to-soil potential readings (at the same points and preferably at low potential spots) every two months, recording these readings and comparing them with past readings to see if they are above 850 millivolts and that there has been no substantial charge in potential. It is not possible under all

	conditions to infer satisfactory operation of a cathodic protection rectifier or other impressed current power source from periodic pipe-to-soil reading comparisons. We believe that Section 192.465(b) requires rectifier operation to be confirmed by direct observation of meters, indicator lights, or other instrumentation attached to the rectifier. **Interpretation: PI-76-081 Date: December 28, 1976** Clarifies that an electrical survey consisting of "a pipe-to-soil survey, atmospheric corrosion survey, pH survey, and determination (and protection) of any 'hot spots'" meets the requirements of 49 CFR 192.457(b) and 192.465(e), provided that it was carried out by or under the direction of a person qualified by experience and training in pipeline corrosion control methods. **Interpretation: PI-76-064 Date: September 20, 1976** Clarifies that Section 192.457(b) requires the line be electrically surveyed for active corrosion and tests be performed or directed by a person qualified by experience or training in corrosion control methods. The "operator" of the line as defined in Section 192.3 would be responsible for making the test and the time requirements are set out in the applicable gas pipeline safety standards. The term "cathodic engineer" is not used in the Federal standards. **Interpretation: PI-76-011 Date: March 3, 1976** Clarifies that tests are required on separately protected service lines once every 10 years including meter risers where metal is the gas carrier when used with a plastic service line." If gas is carried in metal piping that extends below the ground surface, operators of such piping must monitor these short sections as required in 192.465(a). **Interpretation: PI-76-009 Date: January 07, 1976** Clarifies how often individual anodes must be monitored on an unprotected bare transmission or distribution pipeline that has 'hot spot' protection, in which 'hot spot' protection would include anodes installed in connection with corrosion-leak repair clamps?" 49 CFR Part 192, Subpart I, Requirements for Corrosion Control, contains no requirements for monitoring individual anodes. However, Sections 192.457 and 192.465 provide requirements for corrosion control and monitoring of bare transmission or distribution pipelines. **Interpretation: PI-74-009 Date: February 02, 1974** Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465. **Interpretation: PI-74-004 Date: January 24, 1974** Clarifies that metallic riser pipes are to be coated and cathodically protected as required by Section 192.455. The level of protection must meet one or more of the criteria contained in Section 192.463 and the frequency for monitoring service risers is covered by Section 192.465. **Interpretation: PI-73-025 Date: September 26, 1973** Clarifies that if annual tests are impractical for separately protected short sections of

	mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. The survey must cover at least 10 percent of these protected structures, distributed over the entire system, each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period." The sampling percentage may not be adjusted to less than 10% of the protected structures each calendar year. **Interpretation: PI-73-010 Date: May 9, 1973** #1: Clarifies that bare transmission or distribution lines laid prior to August 1, 1971, in areas of "Active Corrosion" must be cathodically protected. This is applicable if corrosion is now detrimental to public safety or, if continuing corrosion, could become detrimental to public safety at a later date. #2: Clarifies that Section 192.465(e) requires each operator to reevaluate its unprotected pipelines at intervals not exceeding three years. The reevaluation is done by electrical survey where practical. A pipeline protected by the "hot spotting" method is an unprotected pipeline for purposes of §192.465 and therefore subject to the three-year reevaluation requirement. The "hot spots," of course, are subject to other monitoring requirements. **Interpretation: PI-71-088 Date: December 20, 1971** Clarifies that when a bare distribution or transmission pipeline is under full cathodic protection, whether the protection is provided by an impressed current type system or by galvanic anodes, the system must be checked at least once a year in accordance with Section 192.465(a) and the level of cathodic protection must meet the requirements of Section 192.463. The cathodic protection system must protect the pipeline in its entirety and it is the operator's responsibility to determine what spacing is required between pipe-to-soil potential measurements to ensure the pipeline is protected. At intervals not exceeding three years, a complete survey is to be conducted over the entirety of a given bare line or system under "hot spot" protection to reevaluate unprotected portions and protect where active corrosion is detected. A reevaluation survey must be conducted as thoroughly as the original survey." The 10% resurvey does not apply to "hot spot" protection and tests of "hot spot" protected sections of electrically continuous pipelines must be made each year. When "hot spot" protection is involved, the operator must resurvey their bare pipeline at intervals not exceeding three years, and provide cathodic protection in each area where active corrosion is found (Section 192.465(e)).
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. This requirement is usually referred to as the "annual CP survey". 2. For distribution system operators. i. The operator must have developed an effective program to monitor its cathodically protected pipe. Piping under cathodic protection must be monitored by electrical measurement each calendar year with intervals not exceeding 15 months. The operator must have documentation to prove that he is monitoring his short, less than 100 feet, separately protected isolated sections of piping, services,

	short sections of coated steel pipeline, and anodes installed according to § 192.483 (c) and §192.457 (b) on a 10 percent annual basis. At least 10 percent of these protected structures, distributed over the entire system, must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period. (Note: Short, less than 100' ft. sections of pipe which are interconnected by cable, tracer wire, or other means, and are protected by a common current source or distributed anodes, are not considered to be isolated and must be monitored as a cathodic protection system on a annual basis.) ii. Operators who are electrically monitoring their entire bare (ineffectively coated) sections of pipeline on a 3-year basis (one third per year) would not have to include their hot spot protected sections of pipe in the 10 percent monitoring program.2. For transmission line operators. 3. Transmission line operators must test by electrical measurement all cathodically protected pipelines once each calendar year with intervals not exceeding 15 months. Short sections of separately protected coated and hot spot protected bare (ineffectively coated) sections of pipeline must be surveyed on an annual 10 percent basis with a different 10 percent checked each subsequent year so that all these sections are tested in each 10-year period. Transmission operators who are electrically monitoring their entire bare (ineffectively coated) sections of pipeline on a one-third per year basis would not have to include their hot spot protected sections of pipeline in a 10 percent monitoring program. 4. The operator must survey at least 10% of their isolated short sections of mains, transmission lines, and services on a sampling basis. (A company with 10 towns or districts which is reading one town or district each year is not surveying on a sampling basis, 10% of each town or district must be surveyed with a different 10% being surveyed each year so that the entire system is tested in each ten year period.) 5. Distribution and transmission operators monitoring isolated short sections of galvanic anode protected pipeline on a 10-year basis, should perform design calculations to verify that the cathodic protection system will remain effective until the next required monitoring.
Examples of a Probable Violation or Inadequate Procedures	1. The operator does not inspect its cathodically protected pipeline at least once each calendar year or at intervals less than 15 months to determine whether one or more requirements of §192.463 are met, and the pipeline is not a separately protected service line or a section of protected pipeline less than 100 feet in length. 2. The operator surveys less than 10 percent of its separately protected service lines or sections of protected pipeline of less than 100 feet, distributed over the entire system, each calendar year. See inspection guideline (ii). 3. The operator's sampling procedure required for separately protected structures does not result in a survey of a different 10 percent each subsequent year, so that the entire system is tested in each 10-year period, See inspection guideline (ii). 4. The operator cannot provide documentation that galvanic anode cathodic protection systems on transmission lines, mains, services, and isolated short sections that are monitored on a 10 year sampling basis are designed to maintain the cathodic protection level to one of the criteria listed in Appendix "D" of Part 192, until the next scheduled read cycle. 5. ***Williston Basin Interstate Pipeline Company [3-2005-1008]*** **(June 21, 2007)** – Found that operator failed to conduct annual cathodic protection testing at five of its electrical test stations. If an operator decides to deviate from its established

	procedures and discontinue testing at a particular station or stations, its decision must be based on a determination by a qualified individual, following a technical analysis, that annual testing at that station is no longer necessary to evaluate the effectiveness of the cathodic protection in that area. An operator must document such a decision and its technical justification in its contemporaneous records. Because the 15-month interval gives the operator sufficient flexibility to return to a test station, external factors such as access or flooding do not relieve the operator from the testing requirement. CP *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator’s maintenance records, verification of coating damage by excavation inspection, photographs.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.465(b)**
Section Title	**External corrosion control: Monitoring**
Existing Code Language	Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 ½ months, to insure that it is operating.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	**Interpretation: PI-ZZ-069 Date: November 9, 2005** This interpretation of section 192.465 clarifies the definition of the term “separately protected service lines” to mean a buried or submerged service line that is electrically isolated and cathodically protected from other metallic structures. The interpretation also explains that separate steel service risers that are electrically interconnected and cathodically protected by a common source are not separately protected lines; and that therefore, §192.465(a) requires an operator to monitor such pipelines at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. **Interpretation: PI-93-039 Date: July 16, 1993** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-92-062 Date: November 23, 1992** This interpretation clarifies that an operator is in compliance with § 192.463(a) as long as each point tested under § 192.465(a) meets any one of the Appendix D criteria or its equivalent. If further clarifies that no additional test data are required provided one of the criteria of the Appendix D is met. Lastly, the interpretation clarifies that the operator's corrosion control procedures under § 192.453 should, at a minimum, specify the criterion used for each segment of its pipeline. **Interpretation: PI-ZZ-068 Date: October 13, 1992** Clarifies the applicability of §192.465 to jurisdictional sections of a buried gathering line. Part §192.465 requires cathodically protected jurisdictional sections to be tested once each calendar year, even if the remainder of the gathering line is not protected. The phrase "in its entirety," as cited in 192.455(a)(2), embraces only pipelines or sections of pipeline which are subject to Part 192. A line does not have to be cathodically protected from end to end if part of the line is non-jurisdictional; only the jurisdictional portion requires cathodic protection.

Interpretation: PI-91-032 Date: November 7, 1991

This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data.

Interpretation: PI-91-025 Date: August 29, 1991

Clarifies that Appendix D, Part II, Part 192, is clear that voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of voltage measurements. When an operator claims they have accounted for IR drop, OPS will accept that claim. If, however, the operator had a leak due to corrosion, OPS may ask the operator to demonstrate the adequacy of corrosion protection and how the operator considered the IR drop and if this was done improperly, the operator could be subject to enforcement action. It is possible to consider the IR drop on magnesium anode protected systems if an inspector or operator places the half cell on the surface of the soil/ground and obtains an abnormally high potential, there is a good possibility that the half cell is over an anode. To ensure that it is not, an inspector or operator should simply move the half cell upstream or downstream from that point and take a reading. OPS does not require operators to disconnect anode wires in order to read instant-off potentials on distributed sacrificial anode protected systems.

Interpretation: PI-ZZ-080 August 19, 1991

Clarifies that an operator has the freedom to conduct its inspections, of rectifiers or other impressed current power sources, utilizing whatever technology or means they choose. The acceptability of electronic data collection and the subsequent broadcast of this data to operators as a means of inspection would depend on the capability to meet §192.465(b) and would also depend on the reliability of the data transmitted to operators. Federal and State field inspectors would review the data to determine its relevance when conducting an inspection.

Interpretation: PI-89-003 Date: March 31, 1989

This interpretation clarifies that if an operator voluntarily places a cathodic protection system on a gas pipeline installed prior to August 1, 1971, with no evidence of active corrosion, the operator should assure that their program properly addressed all the requirements of the regulations, such as using the definition of active corrosion under §192.457(c). The interpretation also clarifies that in determining whether the electrical survey required by §192.457(b)(3) and §192.465(e) is impractical, the operator must consider all factors that relate to the impracticality, including public safety.

Interpretation: PI-85-009 Date: October 24, 1985

Clarifies that permanent potential monitoring test stations, placed throughout a steel gas distribution system which is completely welded (no couplings) and checked on a monthly basis, satisfy the annual "test for cathodic protection" requirement. If an operator tests at sufficient test stations per §192.469 and demonstrates compliance with §192.463, then the testing would also comply with the requirements of §192.465(a).

	Interpretation: PI-81-011 Date: May 29, 1981 Clarifies that compliance with 49 CFR 192.465(a), requires cathodically protected pipelines be tested annually to determine if protection is at the levels required by §192.463 and Appendix D to Part 192. The regulations do not require the use of specific testing methods, and any technique may be used that accurately shows the cathodic protection levels. This office does not recommend one test method over another, and our approval is not needed for an operator to use a new method. **Interpretation: PI-ZZ-070 Date: November 15, 1979** #1 Clarifies that Section 192.465(a) requires all pipelines under cathodic protection to be tested at least once each calendar year to determine compliance with §192.463, with the exception of service lines and short sections of protected mains 100 feet or less in length, which may be tested on a sampling basis. Sampling of these short sections must be done so that at least 10% of the total short piping segments within the pipeline system are tested each calendar year. The tests required must determine whether the cathodic protection requirements of §192.463 and Appendix D are being met. #2 Clarifies that Section 192.465(c) sets monitoring requirements for the effectiveness of equipment installed to prevent damage due to stray currents. Section 192.473(a) requires each operator to minimize the effects of stray currents on its pipeline and (b) minimize the effects of stray currents from its cathodic protection system on existing adjacent underground metallic structures. If stray current from a pipeline cathodic protection system is causing damage to another underground metallic pipeline system or structure (owned by the same operator or others), the operator must minimize the detrimental effects of such currents. "Other interference bonds" as referred to in §192.465(c) are bonds whose failure would not jeopardize structure protection. #3 Clarifies that §192.473(b) requires both impressed current and galvanic anode cathodic protection systems to be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures. Where an adverse effect is determined to exist on an adjacent underground structure, §192.473(b) would require corrective action. In addition, there may be other legal responsibility for damage done by rectifiers. #4 Clarifies that compliance with a given requirement is mandatory on and after the effective date. Section 192.465 became effective on August 1, 1971, and §192.473 on July 31, 1973. Service lines subject to Part 192 installed after July 31, 1971, must have had a cathodic protection system in place within 1 year after the line was installed (§192.455). Under §192.457, other service lines were required to be electrically surveyed for areas of active corrosion and cathodically protected in those areas by August 1, 1976. **Interpretation: PI-ZZ-077 Date: August 23, 1978** Clarifies that a rectifier cannot be inspected to ensure that it is operating (Section 192.465, paragraph b) by taking pipe-to-soil potential readings (at the same points and preferably at low potential spots) every two months, recording these readings and comparing them with past readings to see if they are above 850 millivolts and that there has been no substantial charge in potential. It is not possible under all conditions to infer satisfactory operation of a cathodic protection rectifier or other impressed current power source from periodic pipe-to-soil reading comparisons. We believe that Section 192.465(b) requires rectifier operation to be confirmed by direct observation of meters, indicator lights, or other instrumentation attached to the rectifier.

Interpretation: PI-76-064 Date: December 28, 1976

Clarifies that an electrical survey consisting of "a pipe-to-soil survey, atmospheric corrosion survey, pH survey, and determination (and protection) of any 'hot spots'" meets the requirements of 49 CFR 192.457(b) and 192.465(e), provided that it was carried out by or under the direction of a person qualified by experience and training in pipeline corrosion control methods.

Interpretation: PI-76-064 Date: September 20, 1976

Clarifies that Section 192.457(b) requires the line be electrically surveyed for active corrosion and tests be performed or directed by a person qualified by experience or training in corrosion control methods. The "operator" of the line as defined in Section 192.3 would be responsible for making the test and the time requirements are set out in the applicable gas pipeline safety standards. The term "cathodic engineer" is not used in the Federal standards.

Interpretation: PI-ZZ-074 Date: September 17, 1976

Clarifies that in accordance with Question 6 of the July 1976 Advisory Bulletin, each "hot spot" protected area on a transmission line must be tested annually. Under 49 CFR 192.465(a), each cathodically protected section of a transmission line must be tested annually. The number of protected sections may be less than the number of "hot spot" areas if protected sections include more than one "hot spot" area.

Interpretation: PI-76-011 Date: March 3, 1976

Clarifies that tests are required on separately protected service lines once every 10 years including meter risers where metal is the gas carrier when
used with a plastic service line." If gas is carried in metal piping that extends below the ground surface, operators of such piping must monitor these short sections as required in 192.465(a).

Interpretation: PI-76-009 Date: January 07, 1976 – Clarifies how often individual anodes must be monitored on an unprotected bare transmission or distribution pipeline that has 'hot spot' protection, in which 'hot spot' protection would include anodes installed in connection with corrosion-leak repair clamps?" 49 CFR Part 192, Subpart I, Requirements for Corrosion Control, contains no requirements for monitoring individual anodes. However, Sections 192.457 and 192.465 provide requirements for corrosion control and monitoring of bare transmission or distribution pipelines.

Interpretation: PI-74-009 Date: February 02, 1974

Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465.

Interpretation: PI-74-004 Date: January 24, 1974

Clarifies that metallic riser pipes are to be coated and cathodically protected as required by Section 192.455.
The level of protection must meet one or more of the criteria contained in Section 192.463 and the frequency for monitoring service risers is covered by Section 192.465.

	Interpretation: PI-73-025 Date: September 26, 1973 Clarifies that if annual tests are impractical for separately protected short sections of mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. The survey must cover at least 10 percent of these protected structures, distributed over the entire system, each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period." The sampling percentage may not be adjusted to less than 10% of the protected structures each calendar year. **Interpretation: PI-73-010 Date: May 9, 1973** #1: Clarifies that bare transmission or distribution lines laid prior to August 1, 1971, in areas of "Active Corrosion" must be cathodically protected. This is applicable if corrosion is now detrimental to public safety or, if continuing corrosion, could become detrimental to public safety at a later date. #2: Clarifies that Section 192.465(e) requires each operator to reevaluate its unprotected pipelines at intervals not exceeding three years. The reevaluation is done by electrical survey where practical. A pipeline protected by the "hot spotting" method is an unprotected pipeline for purposes of §192.465 and therefore subject to the three-year reevaluation requirement. The "hot spots," of course, are subject to other monitoring requirements. **Interpretation: PI-71-088 Date: December 20, 1971** Clarifies that when a bare distribution or transmission pipeline is under full cathodic protection, whether the protection is provided by an impressed current type system or by galvanic anodes, the system must be checked at least once a year in accordance with Section 192.465(a) and the level of cathodic protection must meet the requirements of Section 192.463. The cathodic protection system must protect the pipeline in its entirety and it is the operator's responsibility to determine what spacing is required between pipe-to-soil potential measurements to ensure the pipeline is protected. At intervals not exceeding three years, a complete survey is to be conducted over the entirety of a given bare line or system under "hot spot" protection to reevaluate unprotected portions and protect where active corrosion is detected. A reevaluation survey must be conducted as thoroughly as the original survey." The 10% resurvey does not apply to "hot spot" protection and tests of "hot spot" protected sections of electrically continuous pipelines must be made each year. When "hot spot" protection is involved, the operator must resurvey their bare pipeline at intervals not exceeding three years, and provide cathodic protection in each area where active corrosion is found (Section 192.465(e)).
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	The operator is required to inspect its cathodic protection rectifiers or other impressed current power sources in its gas pipeline system at least 6 times each calendar year and not exceeding 2-1/2 months interval.
Examples of a Probable Violation or	1. The operator did not inspect each cathodic protection rectifier or other impressed current power source six times each calendar year at periods not exceeding 2 ½ months.

Inadequate Procedures	2. The operator does not have documentation showing that the rectifier or other impressed current source was inspected at the required intervals. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's O & M manual. 2. Maintenance records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.465(c)**
Section Title	**External corrosion control: Monitoring**
Existing Code Language	Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2 ½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	**Interpretation: PI-ZZ-069 Date: November 9, 2005** This interpretation of section 192.465 clarifies the definition of the term "separately protected service lines" to mean a buried or submerged service line that is electrically isolated and cathodically protected from other metallic structures. The interpretation also explains that separate steel service risers that are electrically interconnected and cathodically protected by a common source are not separately protected lines; and that therefore, §192.465(a) requires an operator to monitor such pipelines at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. **Interpretation: PI-93-039 Date: July 16, 1993** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-92-062 Date: November 23, 1992** This interpretation clarifies that an operator is in compliance with § 192.463(a) as long as each point tested under § 192.465(a) meets any one of the Appendix D criteria or its equivalent. If further clarifies that no additional test data are required provided one of the criteria of the Appendix D is met. Lastly, the interpretation clarifies that the operator's corrosion control procedures under § 192.453 should, at a minimum, specify the criterion used for each segment of its pipeline. **Interpretation: PI-ZZ-068 Date: October 13, 1992** Clarifies the applicability of §192.465 to jurisdictional sections of a buried gathering line. Part §192.465 requires cathodically protected jurisdictional sections to be tested once each calendar year, even if the remainder of the gathering line is not protected. The phrase "in its entirety," as cited in 192.455(a)(2), embraces only pipelines or sections of pipeline which are subject to Part 192. A line does not have to be cathodically protected from end to end if part of the line is non-jurisdictional; only the jurisdictional portion requires cathodic protection.

Interpretation: PI-91-032 Date: November 7, 1991

This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data.

Interpretation: PI-91-025 Date: August 29, 1991

Clarifies that Appendix D, Part II, Part 192, is clear that voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of voltage measurements. When an operator claims they have accounted for IR drop, OPS will accept that claim. If, however, the operator had a leak due to corrosion, OPS may ask the operator to demonstrate the adequacy of corrosion protection and how the operator considered the IR drop and if this was done improperly, the operator could be subject to enforcement action. It is possible to consider the IR drop on magnesium anode protected systems if an inspector or operator places the half cell on the surface of the soil/ground and obtains an abnormally high potential, there is a good possibility that the half cell is over an anode. To ensure that it is not, an inspector or operator should simply move the half cell upstream or downstream from that point and take a reading. OPS does not require operators to disconnect anode wires in order to read instant-off potentials on distributed sacrificial anode protected systems.

Interpretation: PI-ZZ-080 Date: August 19, 1991

Clarifies that an operator has the freedom to conduct its inspections, of rectifiers or other impressed current power sources, utilizing whatever technology or means they choose. The acceptability of electronic data collection and the subsequent broadcast of this data to operators as a means of inspection would depend on the capability to meet §192.465(b) and would also depend on the reliability of the data transmitted to operators. Federal and State field inspectors would review the data to determine its relevance when conducting an inspection.

Interpretation: PI-89-003 Date: March 31, 1989

This interpretation clarifies that if an operator voluntarily places a cathodic protection system on a gas pipeline installed prior to August 1, 1971, with no evidence of active corrosion, the operator should assure that their program properly addressed all the requirements of the regulations, such as using the definition of active corrosion under §192.457(c). The interpretation also clarifies that in determining whether the electrical survey required by §192.457(b)(3) and §192.465(e) is impractical, the operator must consider all factors that relate to the impracticality, including public safety.

Interpretation: PI-85-009 Date: October 24, 1985

Clarifies that permanent potential monitoring test stations, placed throughout a steel gas distribution system which is completely welded (no couplings) and checked on a monthly basis, satisfy the annual "test for cathodic protection" requirement. If an operator tests at sufficient test stations per §192.469 and demonstrates compliance with §192.463, then the testing would also comply with the requirements of §192.465(a).

Interpretation: PI-81-011 Date: May 29, 1981

Clarifies that compliance with 49 CFR 192.465(a), requires cathodically protected pipelines be tested annually to determine if protection is at the levels required by §192.463 and Appendix D to Part 192. The regulations do not require the use of specific testing methods, and any technique may be used that accurately shows the cathodic protection levels. This office does not recommend one test method over another, and our approval is not needed for an operator to use a new method.

Interpretation: PI-ZZ-070 Date: November 15, 1979

#1 Clarifies that Section 192.465(a) requires all pipelines under cathodic protection to be tested at least once each calendar year to determine compliance with §192.463, with the exception of service lines and short sections of protected mains 100 feet or less in length, which may be tested on a sampling basis. Sampling of these short sections must be done so that at least 10% of the total short piping segments within the pipeline system are tested each calendar year. The tests required must determine whether the cathodic protection requirements of §192.463 and Appendix D are being met.

#2 Clarifies that Section 192.465(c) sets monitoring requirements for the effectiveness of equipment installed to prevent damage due to stray currents. Section 192.473(a) requires each operator to minimize the effects of stray currents on its pipeline and (b) minimize the effects of stray currents from its cathodic protection system on existing adjacent underground metallic structures. If stray current from a pipeline cathodic protection system is causing damage to another underground metallic pipeline system or structure (owned by the same operator or others), the operator must minimize the detrimental effects of such currents. "Other interference bonds" as referred to in §192.465(c) are bonds whose failure would not jeopardize structure protection.

#3 Clarifies that §192.473(b) requires both impressed current and galvanic anode cathodic protection systems to be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures. Where an adverse effect is determined to exist on an adjacent underground structure, §192.473(b) would require corrective action. In addition, there may be other legal responsibility for damage done by rectifiers.

#4 Clarifies that compliance with a given requirement is mandatory on and after the effective date. Section 192.465 became effective on August 1, 1971, and §192.473 on July 31, 1973. Service lines subject to Part 192 installed after July 31, 1971, must have had a cathodic protection system in place within 1 year after the line was installed (§192.455). Under §192.457, other service lines were required to be electrically surveyed for areas of active corrosion and cathodically protected in those areas by August 1, 1976.0

Interpretation: PI-ZZ-077 Date: August 23, 1978

Clarifies that a rectifier cannot be inspected to ensure that it is operating (Section 192.465, paragraph b) by taking pipe-to-soil potential readings (at the same points and preferably at low potential spots) every two months, recording these readings and comparing them with past readings to see if they are above 850 millivolts and that there has been no substantial charge in potential. It is not possible under all conditions to infer satisfactory operation of a cathodic protection rectifier or other impressed current power source from periodic pipe-to-soil reading comparisons. We believe that Section 192.465(b) requires rectifier operation to be confirmed by direct observation of meters, indicator lights, or other instrumentation attached to the rectifier.

	Interpretation: PI-76-064 Date: December 28, 1976 Clarifies that an electrical survey consisting of "a pipe-to-soil survey, atmospheric corrosion survey, pH survey, and determination (and protection) of any 'hot spots'" meets the requirements of 49 CFR 192.457(b) and 192.465(e), provided that it was carried out by or under the direction of a person qualified by experience and training in pipeline corrosion control methods. **Interpretation: PI-76-064 Date: September 20, 1976** Clarifies that Section 192.457(b) requires the line be electrically surveyed for active corrosion and tests be performed or directed by a person qualified by experience or training in corrosion control methods. The "operator" of the line as defined in Section 192.3 would be responsible for making the test and the time requirements are set out in the applicable gas pipeline safety standards. The term "cathodic engineer" is not used in the Federal standards. **Interpretation: PI-ZZ-074 Date: September 17, 1976** Clarifies that in accordance with Question 6 of the July 1976 Advisory Bulletin, each "hot spot" protected area on a transmission line must be tested annually. Under 49 CFR 192.465(a), each cathodically protected section of a transmission line must be tested annually. The number of protected sections may be less than the number of "hot spot" areas if protected sections include more than one "hot spot" area. **Interpretation: PI-76-011 Date: March 3, 1976** Clarifies that tests are required on separately protected service lines once every 10 years including meter risers where metal is the gas carrier when used with a plastic service line." If gas is carried in metal piping that extends below the ground surface, operators of such piping must monitor these short sections as required in 192.465(a). **Interpretation: PI-76-009 Date: January 07, 1976** Clarifies how often individual anodes must be monitored on an unprotected bare transmission or distribution pipeline that has 'hot spot' protection, in which 'hot spot' protection would include anodes installed in connection with corrosion-leak repair clamps?" 49 CFR Part 192, Subpart I, Requirements for Corrosion Control, contains no requirements for monitoring individual anodes. However, Sections 192.457 and 192.465 provide requirements for corrosion control and monitoring of bare transmission or distribution pipelines. **Interpretation: PI-74-009 Date: February 02, 1974** Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465. **Interpretation: PI-74-004 Date: January 24, 1974** Clarifies that metallic riser pipes are to be coated and cathodically protected as required by Section 192.455. The level of protection must meet one or more of the criteria contained in Section 192.463 and the frequency for monitoring service risers is covered by Section 192.465.

	Interpretation: PI-73-025 Date: September 26, 1973 Clarifies that if annual tests are impractical for separately protected short sections of mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. The survey must cover at least 10 percent of these protected structures, distributed over the entire system, each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period." The sampling percentage may not be adjusted to less than 10% of the protected structures each calendar year. **Interpretation: PI-73-010 Date: May 9, 1973** #1: Clarifies that bare transmission or distribution lines laid prior to August 1, 1971, in areas of "Active Corrosion" must be cathodically protected. This is applicable if corrosion is now detrimental to public safety or, if continuing corrosion, could become detrimental to public safety at a later date. #2: Clarifies that Section 192.465(e) requires each operator to reevaluate its unprotected pipelines at intervals not exceeding three years. The reevaluation is done by electrical survey where practical. A pipeline protected by the "hot spotting" method is an unprotected pipeline for purposes of §192.465 and therefore subject to the three-year reevaluation requirement. The "hot spots," of course, are subject to other monitoring requirements. **Interpretation: PI-71-088 Date: December 20, 1971** Clarifies that when a bare distribution or transmission pipeline is under full cathodic protection, whether the protection is provided by an impressed current type system or by galvanic anodes, the system must be checked at least once a year in accordance with Section 192.465(a) and the level of cathodic protection must meet the requirements of Section 192.463. The cathodic protection system must protect the pipeline in its entirety and it is the operator's responsibility to determine what spacing is required between pipe-to-soil potential measurements to ensure the pipeline is protected. At intervals not exceeding three years, a complete survey is to be conducted over the entirety of a given bare line or system under "hot spot" protection to reevaluate unprotected portions and protect where active corrosion is detected. A reevaluation survey must be conducted as thoroughly as the original survey." The 10% resurvey does not apply to "hot spot" protection and tests of "hot spot" protected sections of electrically continuous pipelines must be made each year. When "hot spot" protection is involved, the operator must resurvey their bare pipeline at intervals not exceeding three years, and provide cathodic protection in each area where active corrosion is found (Section 192.465(e)).
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator should have developed procedures for determining whether or not structure protection would be jeopardized if any of its reverse current switches, diodes, or interference bonds devices failed and should be able to identify which of these devices present on its system are considered critical and which are not.

	2. The operator's procedures should also delineate how these devices are to be checked and require the checks at the appropriate intervals. 3. Reverse current switches and diodes are sometimes utilized to protect from lighting strikes or to mitigate the effects of large DC current sources such as transit systems or mining operations. If used for these applications, then the devices are likely to be critical and require checking at the more frequent intervals. 4. A sized resistor is frequently used to limit the flow of current through a bond. If used, the operator's procedures should delineate how the resistor will be sized. 5. In general, if cathodic protection current is flowing through the bond back off of the operator's pipeline to a foreign structure, then the bond is likely to be critical. Some operator's may consider the bond critical only if the pipe-to-soil potential on its pipeline drops below one of the accepted criteria if the bond fails, even though the current may be flowing off the pipeline through the bond. In this case, the bond would require the more frequent checks. 6. If cathodic protection current is returning to the operator's pipeline from the foreign structure, then the bond is probably not a critical one and will only require annual monitoring. Be aware, however, that if the foreign structure is another pipeline, the bond may be considered critical to the operator of that pipeline. 7. In many cases, critical bonds may be present to simplify the application of cathodic protection and are not considered critical. In some cases, however, significant interference may occur to one of the pipeline systems should the bond fail. In this case, it may need to be considered a critical bond.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not electrically check each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection. The electrical checks must be performed six times each calendar year at intervals not exceeding 2 ½ months. 2. The operator did not check each interference bond whose failure would not jeopardize structure protection at least once every calendar year at intervals not exceeding 15 months. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's O & M manual. 2. Maintenance records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.465(d)**
Section Title	**External corrosion control: Monitoring**
Existing Code Language	Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	**Interpretation: PI-ZZ-069 Date: November 9, 2005** This interpretation of section 192.465 clarifies the definition of the term "separately protected service lines" to mean a buried or submerged service line that is electrically isolated and cathodically protected from other metallic structures. The interpretation also explains that separate steel service risers that are electrically interconnected and cathodically protected by a common source are not separately protected lines; and that therefore, §192.465(a) requires an operator to monitor such pipelines at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. **Interpretation: PI-93-039 Date: July 16, 1993** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-92-062 Date: November 23, 1992** This interpretation clarifies that an operator is in compliance with § 192.463(a) as long as each point tested under § 192.465(a) meets any one of the Appendix D criteria or its equivalent. If further clarifies that no additional test data are required provided one of the criteria of the Appendix D is met. Lastly, the interpretation clarifies that the operator's corrosion control procedures under § 192.453 should, at a minimum, specify the criterion used for each segment of its pipeline. **Interpretation: PI-ZZ-068 Date: October 13, 1992** Clarifies the applicability of §192.465 to jurisdictional sections of a buried gathering line. Part §192.465 requires cathodically protected jurisdictional sections to be tested once each calendar year, even if the remainder of the gathering line is not protected. The phrase "in its entirety," as cited in 192.455(a)(2), embraces only pipelines or sections of pipeline which are subject to Part 192. A line does not have to be cathodically protected from end to end if part of the line is non-jurisdictional; only the jurisdictional portion requires cathodic protection. **Interpretation: PI-91-032 Date: November 7, 1991** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic

	monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-91-025 Date: August 29, 1991** Clarifies that Appendix D, Part II, Part 192, is clear that voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of voltage measurements. When an operator claims they have accounted for IR drop, OPS will accept that claim. If, however, the operator had a leak due to corrosion, OPS may ask the operator to demonstrate the adequacy of corrosion protection and how the operator considered the IR drop and if this was done improperly, the operator could be subject to enforcement action. It is possible to consider the IR drop on magnesium anode protected systems if an inspector or operator places the half cell on the surface of the soil/ground and obtains an abnormally high potential, there is a good possibility that the half cell is over an anode. To ensure that it is not, an inspector or operator should simply move the half cell upstream or downstream from that point and take a reading. OPS does not require operators to disconnect anode wires in order to read instant-off potentials on distributed sacrificial anode protected systems. **Interpretation: PI-ZZ-080 Date: August 19, 1991** Clarifies that an operator has the freedom to conduct its inspections, of rectifiers or other impressed current power sources, utilizing whatever technology or means they choose. The acceptability of electronic data collection and the subsequent broadcast of this data to operators as a means of inspection would depend on the capability to meet §192.465(b) and would also depend on the reliability of the data transmitted to operators. Federal and State field inspectors would review the data to determine its relevance when conducting an inspection. **Interpretation: PI-89-003 Date: March 31, 1989** This interpretation clarifies that if an operator voluntarily places a cathodic protection system on a gas pipeline installed prior to August 1, 1971, with no evidence of active corrosion, the operator should assure that their program properly addressed all the requirements of the regulations, such as using the definition of active corrosion under §192.457(c). The interpretation also clarifies that in determining whether the electrical survey required by §192.457(b)(3) and §192.465(e) is impractical, the operator must consider all factors that relate to the impracticality, including public safety. **Interpretation: PI-85-009 Date: October 24, 1985** Clarifies that permanent potential monitoring test stations, placed throughout a steel gas distribution system which is completely welded (no couplings) and checked on a monthly basis, satisfy the annual "test for cathodic protection" requirement. If an operator tests at sufficient test stations per §192.469 and demonstrates compliance with §192.463, then the testing would also comply with the requirements of §192.465(a). **Interpretation: PI-81-011 Date: May 29, 1981** Clarifies that compliance with 49 CFR 192.465(a), requires cathodically protected pipelines be tested annually to determine if protection is at the levels required by §192.463 and Appendix D to Part 192. The regulations do not require the use of specific testing methods, and any technique may be used that accurately shows the

	cathodic protection levels. This office does not recommend one test method over another, and our approval is not needed for an operator to use a new method. **Interpretation: PI-ZZ-070 Date: November 15, 1979** #1 Clarifies that Section 192.465(a) requires all pipelines under cathodic protection to be tested at least once each calendar year to determine compliance with §192.463, with the exception of service lines and short sections of protected mains 100 feet or less in length, which may be tested on a sampling basis. Sampling of these short sections must be done so that at least 10% of the total short piping segments within the pipeline system are tested each calendar year. The tests required must determine whether the cathodic protection requirements of §192.463 and Appendix D are being met. #2 Clarifies that Section 192.465(c) sets monitoring requirements for the effectiveness of equipment installed to prevent damage due to stray currents. Section 192.473(a) requires each operator to minimize the effects of stray currents on its pipeline and (b) minimize the effects of stray currents from its cathodic protection system on existing adjacent underground metallic structures. If stray current from a pipeline cathodic protection system is causing damage to another underground metallic pipeline system or structure (owned by the same operator or others), the operator must minimize the detrimental effects of such currents. "Other interference bonds" as referred to in §192.465(c) are bonds whose failure would not jeopardize structure protection. #3 Clarifies that §192.473(b) requires both impressed current and galvanic anode cathodic protection systems to be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures. Where an adverse effect is determined to exist on an adjacent underground structure, §192.473(b) would require corrective action. In addition, there may be other legal responsibility for damage done by rectifiers. #4 Clarifies that compliance with a given requirement is mandatory on and after the effective date. Section 192.465 became effective on August 1, 1971, and §192.473 on July 31, 1973. Service lines subject to Part 192 installed after July 31, 1971, must have had a cathodic protection system in place within 1 year after the line was installed (§192.455). Under §192.457, other service lines were required to be electrically surveyed for areas of active corrosion and cathodically protected in those areas by August 1, 1976. **Interpretation: PI-ZZ-077 Date: August 23, 1978** Clarifies that a rectifier cannot be inspected to ensure that it is operating (Section 192.465, paragraph b) by taking pipe-to-soil potential readings (at the same points and preferably at low potential spots) every two months, recording these readings and comparing them with past readings to see if they are above 850 millivolts and that there has been no substantial charge in potential. It is not possible under all conditions to infer satisfactory operation of a cathodic protection rectifier or other impressed current power source from periodic pipe-to-soil reading comparisons. We believe that Section 192.465(b) requires rectifier operation to be confirmed by direct observation of meters, indicator lights, or other instrumentation attached to the rectifier. **Interpretation: PI-76-081 Date: December 28, 1976** Clarifies that an electrical survey consisting of "a pipe-to-soil survey, atmospheric corrosion survey, pH survey, and determination (and protection) of any 'hot spots'" meets the requirements of 49 CFR 192.457(b) and 192.465(e), provided that it was carried out by or under the direction of a person qualified by experience and training

in pipeline corrosion control methods.

Interpretation: PI-76-064 Date: September 20, 1976

Clarifies that Section 192.457(b) requires the line be electrically surveyed for active corrosion and tests be performed or directed by a person qualified by experience or training in corrosion control methods. The “operator” of the line as defined in Section 192.3 would be responsible for making the test and the time requirements are set out in the applicable gas pipeline safety standards. The term “cathodic engineer” is not used in the Federal standards.

Interpretation: PI-ZZ-074 Date: September 17, 1976

Clarifies that in accordance with Question 6 of the July 1976 Advisory Bulletin, each "hot spot" protected area on a transmission line must be tested annually. Under 49 CFR 192.465(a), each cathodically protected section of a transmission line must be tested annually. The number of protected sections may be less than the number of "hot spot" areas if protected sections include more than one "hot spot" area.

Interpretation: PI-76-011 Date: March 3, 1976

Clarifies that tests are required on separately protected service lines once every 10 years including meter risers where metal is the gas carrier when used with a plastic service line." If gas is carried in metal piping that extends below the ground surface, operators of such piping must monitor these short sections as required in 192.465(a).

Interpretation: PI-76-009 Date: January 07, 1976

Clarifies how often individual anodes must be monitored on an unprotected bare transmission or distribution pipeline that has ’hot spot’ protection, in which ‘hot spot’ protection would include anodes installed in connection with corrosion-leak repair clamps?” 49 CFR Part 192, Subpart I, Requirements for Corrosion Control, contains no requirements for monitoring individual anodes. However, Sections 192.457 and 192.465 provide requirements for corrosion control and monitoring of bare transmission or distribution pipelines.

Interpretation: PI-74-009 Date: February 02, 1974

Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465.

Interpretation: PI-74-004 Date: January 24, 1974

Clarifies that metallic riser pipes are to be coated and cathodically protected as required by Section 192.455.

The level of protection must meet one or more of the criteria contained in Section 192.463 and the frequency for monitoring service risers is covered by Section 192.465.

Interpretation: PI-73-025 Date: September 26, 1973

Clarifies that if annual tests are impractical for separately protected short sections of mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. The survey must cover at least 10 percent of these protected structures, distributed over the entire system, each calendar year, with a different 10 percent checked each

	subsequent year, so that the entire system is tested in each 10-year period." The sampling percentage may not be adjusted to less than 10% of the protected structures each calendar year. **Interpretation: PI-73-010 Date: May 9, 1973** #1: Clarifies that bare transmission or distribution lines laid prior to August 1, 1971, in areas of "Active Corrosion" must be cathodically protected. This is applicable if corrosion is now detrimental to public safety or, if continuing corrosion, could become detrimental to public safety at a later date. #2: Clarifies that Section 192.465(e) requires each operator to reevaluate its unprotected pipelines at intervals not exceeding three years. The reevaluation is done by electrical survey where practical. A pipeline protected by the "hot spotting" method is an unprotected pipeline for purposes of §192.465 and therefore subject to the three-year reevaluation requirement. The "hot spots," of course, are subject to other monitoring requirements. **Interpretation: PI- 71-088 Date: December 20, 1971** Clarifies that when a bare distribution or transmission pipeline is under full cathodic protection, whether the protection is provided by an impressed current type system or by galvanic anodes, the system must be checked at least once a year in accordance with Section 192.465(a) and the level of cathodic protection must meet the requirements of Section 192.463. The cathodic protection system must protect the pipeline in its entirety and it is the operator's responsibility to determine what spacing is required between pipe-to-soil potential measurements to ensure the pipeline is protected. At intervals not exceeding three years, a complete survey is to be conducted over the entirety of a given bare line or system under "hot spot" protection to reevaluate unprotected portions and protect where active corrosion is detected. A reevaluation survey must be conducted as thoroughly as the original survey." The 10% resurvey does not apply to "hot spot" protection and tests of "hot spot" protected sections of electrically continuous pipelines must be made each year. When "hot spot" protection is involved, the operator must resurvey their bare pipeline at intervals not exceeding three years, and provide cathodic protection in each area where active corrosion is found (Section 192.465(e)).
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The definition of "prompt" will vary with the circumstances. Enforcement should be sought when the investigator is convinced that corrective action was not initiated or started in a timely manner. 2. The operator should be required to have procedures (per 192.453) for responding to deficiencies found by the required monitoring. The operator is required to maintain procedures on how prompt remedial action is defined. Those procedures should include as a minimum: a. A time frame for evaluating data and determining a course of action. b. A time frame for any new installation to be operational and cathodic protection to be in the adequate range. c. These time frames should give consideration to the population density and

	environmental concerns of the area that could potentially be affected by released gas. They may also consider climatic conditions, availability of material, workloads, and an estimate of a relative rate of detrimental corrosion. As a rule of thumb, the OPS would expect that, under normal conditions, the operator should have the evaluations and decisions made and action started within a few months, proportionally less where required monitoring is less than a year or where deficiencies could result in an immediate hazard to the public), and correction completed by the time of the next scheduled monitoring. If the operator has no procedure for promptly responding and deficiencies exist, it is a violation of §192.465(d). If you can demonstrate that the operator's established time frame for action is inadequate, you may cite him for a violation or proceed with a notice of amendment or both.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not take prompt remedial action to correct a deficiency indicated by monitoring. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. a. Documentation showing that deficiency was discovered, including operator's records of monitoring performed and the operator's written procedures per §192.605 and §192.613; and 2. b. Documentation showing that corrective action has not been taken; including: i. Statement of absence of action by operator or investigator; or ii. Documentation showing that corrective action was not taken promptly, including operator's record of date of discovery and date of corrective action.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.465(e)**
Section Title	**External corrosion control: Monitoring**
Existing Code Language	After the initial evaluation required by § 192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-114, FR Doc. 2010-19643, Aug 11, 2010]
Interpretation Summaries	**Interpretation: PI-ZZ-069 Date: November 9, 2005** This interpretation of section 192.465 clarifies the definition of the term “separately protected service lines” to mean a buried or submerged service line that is electrically isolated and cathodically protected from other metallic structures. The interpretation also explains that separate steel service risers that are electrically interconnected and cathodically protected by a common source are not separately protected lines; and that therefore, §192.465(a) requires an operator to monitor such pipelines at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. **Interpretation: PI-93-039 Date: July 16, 1993** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-92-062 Date: November 23, 1992** This interpretation clarifies that an operator is in compliance with § 192.463(a) as long as each point tested under § 192.465(a) meets any one of the Appendix D criteria or its equivalent. If further clarifies that no additional test data are required provided one of the criteria of the Appendix D is met. Lastly, the interpretation clarifies that the operator's corrosion control procedures under § 192.453 should, at a minimum, specify the criterion used for each segment of its pipeline. **Interpretation: PI-ZZ-068 Date: October 13, 1992** Clarifies the applicability of §192.465 to jurisdictional sections of a buried gathering line. Part §192.465 requires cathodically protected jurisdictional sections to be

	tested once each calendar year, even if the remainder of the gathering line is not protected. The phrase "in its entirety," as cited in 192.455(a)(2), embraces only pipelines or sections of pipeline which are subject to Part 192. A line does not have to be cathodically protected from end to end if part of the line is non-jurisdictional; only the jurisdictional portion requires cathodic protection. **Interpretation: PI-91-032 Date: November 7, 1991** This interpretation clarifies that an operator has the freedom to assess the performance of its cathodic protection system and conduct its inspections utilizing whatever appropriate technology or means it chooses – including airborne cathodic monitoring equipment – to comply with the inspections under 49 CFR 192.463(a) and §192.465(b) and (c) of rectifiers or other impressed current power source, provided the source technology (in this case, airborne cathodic monitoring equipment) provides reliable data. **Interpretation: PI-91-025 Date: August 29, 1991** Clarifies that Appendix D, Part II, Part 192, is clear that voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of voltage measurements. When an operator claims they have accounted for IR drop, OPS will accept that claim. If, however, the operator had a leak due to corrosion, OPS may ask the operator to demonstrate the adequacy of corrosion protection and how the operator considered the IR drop and if this was done improperly, the operator could be subject to enforcement action. It is possible to consider the IR drop on magnesium anode protected systems if an inspector or operator places the half cell on the surface of the soil/ground and obtains an abnormally high potential, there is a good possibility that the half cell is over an anode. To ensure that it is not, an inspector or operator should simply move the half cell upstream or downstream from that point and take a reading. OPS does not require operators to disconnect anode wires in order to read instant-off potentials on distributed sacrificial anode protected systems. **Interpretation: PI-ZZ-080 Date: August 19, 1991** Clarifies that an operator has the freedom to conduct its inspections, of rectifiers or other impressed current power sources, utilizing whatever technology or means they choose. The acceptability of electronic data collection and the subsequent broadcast of this data to operators as a means of inspection would depend on the capability to meet §192.465(b) and would also depend on the reliability of the data transmitted to operators. Federal and State field inspectors would review the data to determine its relevance when conducting an inspection. **Interpretation: PI-89-003 Date: March 31, 1989** This interpretation clarifies that if an operator voluntarily places a cathodic protection system on a gas pipeline installed prior to August 1, 1971, with no evidence of active corrosion, the operator should assure that their program properly addressed all the requirements of the regulations, such as using the definition of active corrosion under §192.457(c). The interpretation also clarifies that in determining whether the electrical survey required by §192.457(b)(3) and §192.465(e) is impractical, the operator must consider all factors that relate to the impracticality, including public safety. **Interpretation: PI-85-009 Date: October 24, 1985** Clarifies that permanent potential monitoring test stations, placed throughout a steel gas distribution system which is completely welded (no couplings) and checked on a monthly basis, satisfy the annual "test for cathodic protection" requirement. If an

operator tests at sufficient test stations per §192.469 and demonstrates compliance with §192.463, then the testing would also comply with the requirements of §192.465(a).

Interpretation: PI-81-011 Date: May 29, 1981

Clarifies that compliance with 49 CFR 192.465(a), requires cathodically protected pipelines be tested annually to determine if protection is at the levels required by §192.463 and Appendix D to Part 192. The regulations do not require the use of specific testing methods, and any technique may be used that accurately shows the cathodic protection levels. This office does not recommend one test method over another, and our approval is not needed for an operator to use a new method.

Interpretation: PI-ZZ-070 Date: November 15, 1979

#1 Clarifies that Section 192.465(a) requires all pipelines under cathodic protection to be tested at least once each calendar year to determine compliance with §192.463, with the exception of service lines and short sections of protected mains 100 feet or less in length, which may be tested on a sampling basis. Sampling of these short sections must be done so that at least 10% of the total short piping segments within the pipeline system are tested each calendar year. The tests required must determine whether the cathodic protection requirements of §192.463 and Appendix D are being met.

#2 Clarifies that Section 192.465(c) sets monitoring requirements for the effectiveness of equipment installed to prevent damage due to stray currents. Section 192.473(a) requires each operator to minimize the effects of stray currents on its pipeline and (b) minimize the effects of stray currents from its cathodic protection system on existing adjacent underground metallic structures. If stray current from a pipeline cathodic protection system is causing damage to another underground metallic pipeline system or structure (owned by the same operator or others), the operator must minimize the detrimental effects of such currents. "Other interference bonds" as referred to in §192.465(c) are bonds whose failure would not jeopardize structure protection.

#3 Clarifies that §192.473(b) requires both impressed current and galvanic anode cathodic protection systems to be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures. Where an adverse effect is determined to exist on an adjacent underground structure, §192.473(b) would require corrective action. In addition, there may be other legal responsibility for damage done by rectifiers.

#4 Clarifies that compliance with a given requirement is mandatory on and after the effective date. Section 192.465 became effective on August 1, 1971, and §192.473 on July 31, 1973. Service lines subject to Part 192 installed after July 31, 1971,

must have had a cathodic protection system in place within 1 year after the line was installed (§192.455). Under §192.457, other service lines were required to be electrically surveyed for areas of active corrosion and cathodically protected in those areas by August 1, 1976.

Interpretation: PI-ZZ-077 Date: August 23, 1978

Clarifies that a rectifier cannot be inspected to ensure that it is operating (Section 192.465, paragraph b) by taking pipe-to-soil potential readings (at the same points and preferably at low potential spots) every two months, recording these readings and comparing them with past readings to see if they are above 850 millivolts and that there has been no substantial charge in potential. It is not possible under all conditions to infer satisfactory operation of a cathodic protection rectifier or other

	impressed current power source from periodic pipe-to-soil reading comparisons. We believe that Section 192.465(b) requires rectifier operation to be confirmed by direct observation of meters, indicator lights, or other instrumentation attached to the rectifier. **Interpretation: PI-76-081 Date: December 28, 1976** Clarifies that an electrical survey consisting of "a pipe-to-soil survey, atmospheric corrosion survey, pH survey, and determination (and protection) of any 'hot spots'" meets the requirements of 49 CFR 192.457(b) and 192.465(e), provided that it was carried out by or under the direction of a person qualified by experience and training in pipeline corrosion control methods. **Interpretation: PI-76-064 Date: September 20, 1976** Clarifies that Section 192.457(b) requires the line be electrically surveyed for active corrosion and tests be performed or directed by a person qualified by experience or training in corrosion control methods. The "operator" of the line as defined in Section 192.3 would be responsible for making the test and the time requirements are set out in the applicable gas pipeline safety standards. The term "cathodic engineer" is not used in the Federal standards. **Interpretation: PI-ZZ-074 Date: September 17, 1976** Clarifies that in accordance with Question 6 of the July 1976 Advisory Bulletin, each "hot spot" protected area on a transmission line must be tested annually. Under 49 CFR 192.465(a), each cathodically protected section of a transmission line must be tested annually. The number of protected sections may be less than the number of "hot spot" areas if protected sections include more than one "hot spot" area. **Interpretation: PI-76-011 Date: March 3, 1976** Clarifies that tests are required on separately protected service lines once every 10 years including meter risers where metal is the gas carrier when used with a plastic service line." If gas is carried in metal piping that extends below the ground surface, operators of such piping must monitor these short sections as required in 192.465(a). **Interpretation: PI-76-009 Date: January 07, 1976** Clarifies how often individual anodes must be monitored on an unprotected bare transmission or distribution pipeline that has 'hot spot' protection, in which 'hot spot' protection would include anodes installed in connection with corrosion-leak repair clamps?" 49 CFR Part 192, Subpart I, Requirements for Corrosion Control, contains no requirements for monitoring individual anodes. However, Sections 192.457 and 192.465 provide requirements for corrosion control and monitoring of bare transmission or distribution pipelines. **Interpretation: PI-74-009 Date: February 02, 1974** Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465. **Interpretation: PI-74-004 Date: January 24, 1974** Clarifies that metallic riser pipes are to be coated and cathodically protected as required by Section 192.455.

	The level of protection must meet one or more of the criteria contained in Section 192.463 and the frequency for monitoring service risers is covered by Section 192.465. **Interpretation: PI-73-025 Date: September 26, 1973** Clarifies that if annual tests are impractical for separately protected short sections of mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. The survey must cover at least 10 percent of these protected structures, distributed over the entire system, each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period." The sampling percentage may not be adjusted to less than 10% of the protected structures each calendar year. **Interpretation: PI-73-010 Date: May 9, 1973** #1: Clarifies that bare transmission or distribution lines laid prior to August 1, 1971, in areas of "Active Corrosion" must be cathodically protected. This is applicable if corrosion is now detrimental to public safety or, if continuing corrosion, could become detrimental to public safety at a later date. #2: Clarifies that Section 192.465(e) requires each operator to reevaluate its unprotected pipelines at intervals not exceeding three years. The reevaluation is done by electrical survey where practical. A pipeline protected by the "hot spotting" method is an unprotected pipeline for purposes of §192.465 and therefore subject to the three-year reevaluation requirement. The "hot spots," of course, are subject to other monitoring requirements. **Interpretation: PI- 71-088 Date: December 20, 1971** Clarifies that when a bare distribution or transmission pipeline is under full cathodic protection, whether the protection is provided by an impressed current type system or by galvanic anodes, the system must be checked at least once a year in accordance with Section 192.465(a) and the level of cathodic protection must meet the requirements of Section 192.463. The cathodic protection system must protect the pipeline in its entirety and it is the operator's responsibility to determine what spacing is required between pipe-to-soil potential measurements to ensure the pipeline is protected. At intervals not exceeding three years, a complete survey is to be conducted over the entirety of a given bare line or system under "hot spot" protection to reevaluate unprotected portions and protect where active corrosion is detected. A reevaluation survey must be conducted as thoroughly as the original survey." The 10% resurvey does not apply to "hot spot" protection and tests of "hot spot" protected sections of electrically continuous pipelines must be made each year. When "hot spot" protection is involved, the operator must resurvey their bare pipeline at intervals not exceeding three years, and provide cathodic protection in each area where active corrosion is found (Section 192.465(e)).
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	Continuing corrosion occurring in the following areas are considered detrimental to public safety, i.e. "active corrosion":

	1. Urban areas: (a) Most areas within the boundary limits of any incorporated or unincorporated city, town, or village. (b) Any residential or commercial area, such as a subdivision, business or shopping center, or community development. (c) Areas in which the pipeline closely parallels or crosses underground sewers or other utility lines. 2. In an area where the pipeline lies within 100 yards of the following: (a) A building that is intended for human occupancy. (b) A small well-defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theater, or other place of public assembly. 3. At highway and railroad crossings. 4. All underground piping at compressor stations and regulator stations 5. For distribution system operators. i Paragraph 465(e) requires that distribution operators re-evaluate their unprotected pipelines, which were initially evaluated as required by § 192.455(b) and (c) and 192.457(b) at intervals not exceeding 3 years. An electrical survey should, as a first choice, be used by distribution operators to determine areas of active corrosion on these unprotected lines. However, operators need not use electrical survey if it is impractical for their system. Operators need not prove that it is physically impossible to run an electrical survey. A distribution operator should not be cited for not having run electrical surveys over its unprotected bare and ineffectively coated piping system located in wall-to-wall pavement areas, areas where their pipe is in a common trench with other metallic structures, areas where stray currents predominate, or in areas where the pipe is continually going in and out of paved areas (roads, sidewalks, parking lots, etc.). ii. Operators who do not run electrical surveys over their unprotected metallic pipelines must have developed a separate program to effectively monitor unprotected coated and bare (ineffectively coated) pipelines. The operators must demonstrate that they are effectively using their leak history records, leak detection surveys, study of corrosion, and environmental studies to monitor these pipelines. Based on the results of this monitoring, operators must take action to either cathodically protect areas of active corrosion on their system or replace that portion of piping. 7. For transmission line operators: Paragraph (e) requires that transmission line operators re-evaluate their unprotected pipelines, which were initially evaluated as required by §192.455(b) and (c) and §192.457(b), at intervals not exceeding 3 years. Transmission line operators as a first choice should use an electrical survey for the re-evaluation. If transmission line operator chooses not to run an electrical survey to meet the requirements of paragraph (e): 8. The operator must demonstrate why it is "impractical." The operator need not prove physical impossibility. 9. Operator must demonstrate that it has a separate program of leak detection studies, corrosion history studies, and leak history records which are effectively monitoring the pipeline. The overall effectiveness of the program should be judged

	on the ability of an operator to show a significant drop in their corrosion leakage rate or a stabilized minimal corrosion leakage rate. Note: An "electrical survey" defined by 465(e)(2) refers to a close-interval potential survey when it specifies "a series of closely spaced pipe-to-soil potential readings over a pipeline." However, there are other surveys an operator might use to detect corrosion on a bare or ineffectively coated pipeline, such as a "cell-to-cell" or "hot-spot" survey using current reversals and side-drain readings to locate likely corrosive areas. 10. ***West Texas Gas, Inc. [4-2004-1007]* (September 13, 2006)** – Found that operator failed to reevaluate an unprotected pipeline and determine areas of active corrosion by electrical survey at least once every 3 years at intervals not exceeding 39 months. If an operator wishes to use other means to determine areas of active corrosion on a transmission line, the burden is on the operator to show that electrical survey is impractical, and the impracticality cannot be through the fault or shortcoming of the operator. CP, CO
Examples of a Probable Violation or Inadequate Procedures	1. The operator initially evaluated the pipeline pursuant to Section 192.455(b) and (c) or Section 192.457(b), but did not inspect the pipeline at the required intervals. 2. The operator did not set up a separate program to reevaluate these unprotected lines. 3. The operator did not perform a re-evaluation of an unprotected pipeline at least every three years and the pipeline was initially evaluated pursuant to sections 192.455(b) or (c) and 192.457(b). *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's O & M manual. 2. Maintenance records. 3. Statements of operator's personnel.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.467(a)**
Section Title	**External corrosion control: Electrical isolation.**
Existing Code Language	Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.
Origin of Code	NGLPSA 1968
Last Amendment	[Amdt.192-33, 43 FR 39389, Sept. 5, 1978]
Interpretation Summaries	**Interpretation: PI-98-009 Date: November 10, 1998** #1: Clarifies the purpose of § 192.467(f), "close proximity" means near enough to the listed structures to reasonably expect that a lightning strike or fault current involving the structure might harm the pipeline's corrosion control system. Close proximity is not an absolute or minimum distance, and it could vary depending on site conditions. Under § 192.453, the distance must be determined by a person qualified in pipeline corrosion control methods who has knowledge of the circumstances. #2: Insufficient Information. #3: Clarifies that Section 192.467(f) does not specify a threshold voltage in connection with protective measures. This voltage would be determined by a person qualified in pipeline corrosion control methods. #4: Clarifies that Under § 192.467(f), the term "electrical transmission tower" is used in its ordinary sense to refer to tall aboveground steel structures that support cables used to transmit electricity over long distances. The term does not include poles that support cables used to distribute electricity throughout a community. #5: Clarifies that protection is required only against fault currents and lightning and does not include protecting the pipeline from induced currents. **Interpretation: PI-93-053 Date: August 19, 1993** #1: Clarifies that Section 192.467(a) requires each pipeline on which external corrosion control is required to be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit. The electrical interconnection must be designed and installed as a part of the cathodic protection system to enable the pipeline and other structures to be cathodically protected together. #2: Clarifies that Section 192.467(b) requires one or more insulating devices to be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Insulating devices are required only when the portion of pipeline being protected is electrically isolated to achieve the required level of cathodic protection. #3: Clarifies that if a pipeline is not required to have cathodic protection, §192.467(b) does not require the pipeline to have insulating devices.

	Interpretation: PI-75-001 Date: January 9, 1975 Clarifies that 192.457(b)(1) requires bare or ineffectively coated transmission lines installed before August 1, 1971, except for cast or ductile iron lines, be cathodically protected in accordance with Subpart I in areas in where active corrosion is found. 192.467(b)(1) is intended primarily for transmission lines traversing areas with heavy population. The requirements of section 192.457(b)(1) apply regardless of the population of the areas in which a transmission line is located. **Interpretation: PI-74-020 Date: March 18, 1974** Clarifies that 49 CFR Part 192, contains various construction requirements covering problems of installation in a common trench in Subpart G and in §192.467 with respect to corrosion control. The standards do not specifically prohibit common trench installations, but they must meet all applicable requirements in Part 192. **Interpretation: PI-74-009 Date: February 02, 1974** Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465. **Interpretation: PI-73-025 Date: September 26, 1973** Clarifies that if annual tests are impractical for separately protected short sections of mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. The survey must cover at least 10 percent of these protected structures, distributed over the entire system, each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period." The sampling percentage may not be adjusted to less than 10% of the protected structures each calendar year. **Interpretation: PI-72-030 Date: July 14, 1972** Clarifies that Section 192.467(a) does not apply to all gas distribution systems but is intended to apply to all new pipelines. Existing distribution systems are covered by Section 192.467(b), which requires insulation wherever electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Existing distribution lines must be cathodically protected only in areas in which active corrosion is found (Section 192.457(b)(3)). Electrical isolation of existing distribution lines is not required under all circumstances, but only where necessary to facilitate the application of corrosion control required by Section 192.457(b)(3). **Interpretation: PI-ZZ-085 Date: September 24, 1970** Clarifies that DOT jurisdiction would stop at the downstream side of the customer's meter and the "house line" would not be regulated.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary

Guidance Information	1. To facilitate current distribution, pipelines may be divided into segments or isolated from pump station piping by isolating devices. Unintentional shorts to other metallic structures may drop the P/S potentials below the required CP criteria. These shorts should be cleared. Electrical isolation may be accomplished by using: Insulating flange kits, unions, insulating joints, polarization cells, or grounding cells. 2. An operator does not necessarily need to take P/S potentials on non-jurisdictional metallic structures (water, electrical, or grounding systems) that are part of the cathodically protected system. As long as the operator's annual survey on their pipeline meets applicable CP criterion, they are in compliance with 192.465(a). Usually, it is a good practice to take pipe-to-soil readings on both sides of an insulator.
Examples of a Probable Violation or Inadequate Procedures	1. Operator did not demonstrate through inspection and electrical tests, that electrical isolation is adequate or necessary. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's O & M manual. 2. Maintenance records. 3. Photographs.
Other Special Notations	Caution should be exercised when working around isolation devices. High voltage drops may exist across these devices that can present a danger to personnel.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.467(b)**
Section Title	**External corrosion control: Electrical isolation.**
Existing Code Language	One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.
Origin of Code	NGLPSA 1968
Last Amendment	[Amdt.192-33, 43 FR 39389, Sept. 5, 1978]
Interpretation Summaries	**Interpretation: PI-98-009 Date: November 10, 1998** 1. Clarifies the purpose of § 192.467(f), "close proximity" means near enough to the listed structures to reasonably expect that a lightning strike or fault current involving the structure might harm the pipeline's corrosion control system. Close proximity is not an absolute or minimum distance, and it could vary depending on site conditions. Under § 192.453, the distance must be determined by a person qualified in pipeline corrosion control methods who has knowledge of the circumstances. **Interpretation: PI-93-053 Date: August 19, 1993** 1. Clarifies that Section 192.467(a) requires each pipeline on which external corrosion control is required to be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit. The electrical interconnection must be designed and installed as a part of the cathodic protection system to enable the pipeline and other structures to be cathodically protected together. 2. Clarifies that Section 192.467(b) requires one or more insulating devices to be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Insulating devices are required only when the portion of pipeline being protected is electrically isolated to achieve the required level of cathodic protection. 3. Clarifies that if a pipeline is not required to have cathodic protection, §192.467(b) does not require the pipeline to have insulating devices. **Interpretation: PI-75-001 Date: January 9, 1975** Clarifies that 192.457(b)(1) requires bare or ineffectively coated transmission lines installed before August 1, 1971, except for cast or ductile iron lines, be cathodically protected in accordance with Subpart I in areas in where active corrosion is found. 192.467(b)(1) is intended primarily for transmission lines traversing areas with heavy population. The requirements of section 192.457(b)(1) apply regardless of the population of the areas in which a transmission line is located. **Interpretation: PI-74-020 Date: March 18, 1974** Clarifies that 49 CFR Part 192, contains various construction requirements covering

	problems of installation in a common trench in Subpart G and in §192.467 with respect to corrosion control. The standards do not specifically prohibit common trench installations, but they must meet all applicable requirements in Part 192 2. Insufficient Information. 3. Clarifies that Section 192.467(f) does not specify a threshold voltage in connection with protective measures. This voltage would be determined by a person qualified in pipeline corrosion control methods. 4. Clarifies that Under § 192.467(f), the term "electrical transmission tower" is used in its ordinary sense to refer to tall aboveground steel structures that support cables used to transmit electricity over long distances. The term does not include poles that support cables used to distribute electricity throughout a community. 5. Clarifies that protection is required only against fault currents and lightning and does not include protecting the pipeline from induced currents. **Interpretation: PI-74-009 Date: February 02, 1974** Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465. **Interpretation: PI-72-030 Date: July 14, 1972** Clarifies that Section 192.467(a) does not apply to all gas distribution systems but is intended to apply to all new pipelines. Existing distribution systems are covered by Section 192.467(b), which requires insulation wherever electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Existing distribution lines must be cathodically protected only in areas in which active corrosion is found (Section 192.457(b)(3)). Electrical isolation of existing distribution lines is not required under all circumstances, but only where necessary to facilitate the application of corrosion control required by Section 192.457(b)(3). **Interpretation: PI-ZZ-085 Date: September 24, 1970** Clarifies that DOT jurisdiction would stop at the downstream side of the customer's meter and the "house line" would not be regulated.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. To facilitate the application of corrosion control, the operator must install one or more insulating devices in a segment of pipeline where electrical isolation may be necessary. 2. Electrical isolation may be achieved by using an insulating flange kit or any other suitable devices. The pipe-to-soil readings should be taken on both sides of an insulator during annual cathodic protection monitoring or when it is deemed necessary. An operator may also use a flange / insulation checking meter to insure adequate isolation.
Examples of a Probable	1. The operator does not have records to show that insulating devices were installed and testing has been performed and that the isolation is effective.

Violation or Inadequate Procedures	*Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator’s O & M manual. 2. Maintenance records. 3. Photographs.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.467(c)**
Section Title	**External corrosion control: Electrical isolation.**
Existing Code Language	Except for unprotected copper inserted in a ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. If isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.
Origin of Code	NGLPSA 1968
Last Amendment	[Amdt.192-33, 43 FR 39389, Sept. 5, 1978]
Interpretation Summaries	**Interpretation: PI-98-009 Date: November 10, 1998** 1. Clarifies the purpose of § 192.467(f), "close proximity" means near enough to the listed structures to reasonably expect that a lightning strike or fault current involving the structure might harm the pipeline's corrosion control system. Close proximity is not an absolute or minimum distance, and it could vary depending on site conditions. Under § 192.453, the distance must be determined by a person qualified in pipeline corrosion control methods who has knowledge of the circumstances. 2. Insufficient Information. 3. Clarifies that Section 192.467(f) does not specify a threshold voltage in connection with protective measures. This voltage would be determined by a person qualified in pipeline corrosion control methods. 4. Clarifies that Under § 192.467(f), the term "electrical transmission tower" is used in its ordinary sense to refer to tall aboveground steel structures that support cables used to transmit electricity over long distances. The term does not include poles that support cables used to distribute electricity throughout a community. 5. Clarifies that protection is required only against fault currents and lightning and does not include protecting the pipeline from induced currents. **Interpretation: PI-93-053 Date: August 19, 1993** 1. Clarifies that Section 192.467(a) requires each pipeline on which external corrosion control is required to be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit. The electrical interconnection must be designed and installed as a part of the cathodic protection system to enable the pipeline and other structures to be cathodically protected together. 2. Clarifies that Section 192.467(b) requires one or more insulating devices to be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Insulating devices are required only when the portion of pipeline being protected is electrically isolated to achieve the required level of cathodic protection. 3. Clarifies that if a pipeline is not required to have cathodic protection, §192.467(b) does not require the pipeline to have insulating devices.

	Interpretation: PI-75-001 Date: January 9, 1975 Clarifies that 192.457(b)(1) requires bare or ineffectively coated transmission lines installed before August 1, 1971, except for cast or ductile iron lines, be cathodically protected in accordance with Subpart I in areas in where active corrosion is found. 192.467(b)(1) is intended primarily for transmission lines traversing areas with heavy population. The requirements of section 192.457(b)(1) apply regardless of the population of the areas in which a transmission line is located. **Interpretation: PI-74-020 Date: March 18, 1974** Clarifies that 49 CFR Part 192, contains various construction requirements covering problems of installation in a common trench in Subpart G and in §192.467 with respect to corrosion control. The standards do not specifically prohibit common trench installations, but they must meet all applicable requirements in Part 192. **Interpretation: PI-74-009 Date: February 02, 1974** Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465. **Interpretation: PI-72-030 Date: July 14, 1972** Clarifies that Section 192.467(a) does not apply to all gas distribution systems but is intended to apply to all new pipelines. Existing distribution systems are covered by Section 192.467(b), which requires insulation wherever electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Existing distribution lines must be cathodically protected only in areas in which active corrosion is found (Section 192.457(b)(3)). Electrical isolation of existing distribution lines is not required under all circumstances, but only where necessary to facilitate the application of corrosion control required by Section 192.457(b)(3). **Interpretation: PI-ZZ-085 Date: September 24, 1970** Clarifies that DOT jurisdiction would stop at the downstream side of the customer's meter and the "house line" would not be regulated.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. Casings are electrically isolated from carrier pipeline because usually they are uncoated and will drain the current away from the carrier pipeline. 2. To avoid loss of current from the carrier pipeline, casings are electrically isolated from the pipeline. However, sometime this isolation cannot be maintained. This failure may be classified as either direct or electrolytic shorts or couples. Direct shorts occur when the carrier pipe and the casing are in metallic contact. 3. The electrical resistance between the carrier pipe and the casing would be zero ohms. 4. Electrolytic Shorts or Couples occur when an Ionic contact between two metallic structures via an electrolyte takes place. The electrical resistance may vary with

	an electrolytic short or couple and further testing may be required. After a shorted casing has been identified, the operator should determine a course of action to correct or negate the adverse effects of shorted casings. 5. The operator's plan of action should be initiated within six months of completion of the survey. Both types of shorts (direct or electrolytic should be removed since they could reduce the effectiveness of CP to not only the carrier pipe in the casing but to the line pipe on either side of the casing. 6. Performing leak survey in lieu of testing casings for shorted condition is not an acceptable alternative for the operator. 7. ***Tennessee Gas Pipeline Company [2-2007-1011]*** **(July 9, 2010)** – Found that operator had made no attempt to achieve electrical isolation of a casing at a highway crossing and had failed to take measures to minimize corrosion of the pipe inside the shorted casing. Where it is impractical to achieve electronic isolation, operators are required to take other measures to minimize corrosion of the pipe. A decision to use a targeted program of internal inspections and monitoring for this purpose must be well documented and technically sound. Normal cathodic protection maintenance activities do not satisfy this requirement. CP
Examples of a Probable Violation or Inadequate Procedures	1. A cathodically protected transmission, distribution gas pipeline and hazardous liquid pipeline is electrically connected to metallic casings that are a part of the underground system, and within six months of discovery of the electrical short between the casings and pipeline, the operator has not initiated corrective action. The operator's procedures should also be investigated to: a. Determine that the operator has a written procedure to react to a shorted casing. b. Determine that the operator follows the written procedure. c. Metallic short is discovered between pipeline and casing and the operator did not take any remedial action. d. Determine that the operator performs annual testing of casings for shorted conditions. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's procedure on shorted casings, annual pipe to soil & casing to soil readings. Operator's procedure on shorted casings, annual pipe to soil & casing to soil readings.
Other Special Notations	All highway and railroad crossings involving cathodically protected gas and liquid pipelines must be electrically isolated from the casing, or other measures must be used to mitigate galvanic corrosion of the pipeline inside the shorted casing. A pipeline is not protected in its entirety whenever casings are shorted to the pipeline because of the shielding effect of the casings that prevents cathodic protection current from reaching the pipeline inside the casing. An in-line inspection tool (smart pig) is not valid for evaluating casing shorts or for verifying that any cathodic protection criteria are being met on the carrier pipeline. If corrosion is detected on the carrier pipe using an in-line inspection tool, the operator must have a written procedure for evaluating the extent and severity of the corrosion and if necessary, a corrective

	action plan.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.467(d)**
Section Title	**External corrosion control: Electrical isolation.**
Existing Code Language	Inspection and electrical tests must be made to assure that electrical isolation is adequate.
Origin of Code	NGLPSA 1968
Last Amendment	[Amdt.192-33, 43 FR 39389, Sept. 5, 1978]
Interpretation Summaries	**Interpretation: PI-98-009 Date: November 10, 1998** 1. Clarifies the purpose of § 192.467(f), "close proximity" means near enough to the listed structures to reasonably expect that a lightning strike or fault current involving the structure might harm the pipeline's corrosion control system. Close proximity is not an absolute or minimum distance, and it could vary depending on site conditions. Under § 192.453, the distance must be determined by a person qualified in pipeline corrosion control methods who has knowledge of the circumstances. 2. Insufficient Information. 3. Clarifies that Section 192.467(f) does not specify a threshold voltage in connection with protective measures. This voltage would be determined by a person qualified in pipeline corrosion control methods. 4. Clarifies that Under § 192.467(f), the term "electrical transmission tower" is used in its ordinary sense to refer to tall aboveground steel structures that support cables used to transmit electricity over long distances. The term does not include poles that support cables used to distribute electricity throughout a community. 5. Clarifies that protection is required only against fault currents and lightning and does not include protecting the pipeline from induced currents. **Interpretation: PI-93-053 Date: August 19, 1993** 1. Clarifies that Section 192.467(a) requires each pipeline on which external corrosion control is required to be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit. The electrical interconnection must be designed and installed as a part of the cathodic protection system to enable the pipeline and other structures to be cathodically protected together. 2. Clarifies that Section 192.467(b) requires one or more insulating devices to be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Insulating devices are required only when the portion of pipeline being protected is electrically isolated to achieve the required level of cathodic protection. 3. Clarifies that if a pipeline is not required to have cathodic protection, §192.467(b) does not require the pipeline to have insulating devices. **Interpretation: PI-75-001 Date: January 9, 1975** Clarifies that 192.457(b)(1) requires bare or ineffectively coated transmission lines installed before August 1, 1971, except for cast or ductile iron lines, be cathodically

	protected in accordance with Subpart I in areas in where active corrosion is found. 192.467(b)(1) is intended primarily for transmission lines traversing areas with heavy population. The requirements of section 192.457(b)(1) apply regardless of the population of the areas in which a transmission line is located. **Interpretation: PI-74-020 Date: March 18, 1974** Clarifies that 49 CFR Part 192, contains various construction requirements covering problems of installation in a common trench in Subpart G and in §192.467 with respect to corrosion control. The standards do not specifically prohibit common trench installations, but they must meet all applicable requirements in Part 192. **Interpretation: PI-74-009 Date: February 02, 1974** Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465. **Interpretation: PI-72-030 Date: July 14, 1972** Clarifies that Section 192.467(a) does not apply to all gas distribution systems but is intended to apply to all new pipelines. Existing distribution systems are covered by Section 192.467(b), which requires insulation wherever electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Existing distribution lines must be cathodically protected only in areas in which active corrosion is found (Section 192.457(b)(3)). Electrical isolation of existing distribution lines is not required under all circumstances, but only where necessary to facilitate the application of corrosion control required by Section 192.457(b)(3). **Interpretation: PI-ZZ-085 Date: September 24, 1970** Clarifies that DOT jurisdiction would stop at the downstream side of the customer's meter and the "house line" would not be regulated.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator should compile a list of all its electrical isolation locations and must inspect and test them. The operator must define the circumstances under which inspections are required. 2. There are several test methods that can demonstrate electrical isolation without having test leads on the casing and the carrier pipe near the casing and thus the lack of test leads is not an acceptable excuse for not testing for electrical isolation.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not demonstrate through inspection and electrical tests that electrical isolation is adequate. 2. The operator does not have records to show that testing has been performed and that the isolation is effective. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Operator’s O & M manual. 2. Maintenance records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.467(e)**
Section Title	**External corrosion control: Electrical isolation.**
Existing Code Language	An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.
Origin of Code	NGLPSA 1968
Last Amendment	[Amdt.192-33, 43 FR 39389, Sept. 5, 1978]
Interpretation Summaries	**Interpretation: PI-98-009 Date: November 10, 1998** 1. Clarifies the purpose of § 192.467(f), "close proximity" means near enough to the listed structures to reasonably expect that a lightning strike or fault current involving the structure might harm the pipeline's corrosion control system. Close proximity is not an absolute or minimum distance, and it could vary depending on site conditions. Under § 192.453, the distance must be determined by a person qualified in pipeline corrosion control methods who has knowledge of the circumstances. 2. Insufficient Information. 3. Clarifies that Section 192.467(f) does not specify a threshold voltage in connection with protective measures. This voltage would be determined by a person qualified in pipeline corrosion control methods. 4. Clarifies that Under § 192.467(f), the term "electrical transmission tower" is used in its ordinary sense to refer to tall aboveground steel structures that support cables used to transmit electricity over long distances. The term does not include poles that support cables used to distribute electricity throughout a community. 5. Clarifies that protection is required only against fault currents and lightning and does not include protecting the pipeline from induced currents. **Interpretation: PI-93-053 Date: August 19, 1993** 1. Clarifies that Section 192.467(a) requires each pipeline on which external corrosion control is required to be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit. The electrical interconnection must be designed and installed as a part of the cathodic protection system to enable the pipeline and other structures to be cathodically protected together. **Interpretation: PI-75-001 Date: January 9, 1975** Clarifies that 192.457(b)(1) requires bare or ineffectively coated transmission lines installed before August 1, 1971, except for cast or ductile iron lines, be cathodically protected in accordance with Subpart I in areas in where active corrosion is found. 192.467(b)(1) is intended primarily for transmission lines traversing areas with heavy population. The requirements of section 192.457(b)(1) apply regardless of the population of the areas in which a transmission line is located. **Interpretation: PI-74-020 Date: March 18, 1974** 1. Clarifies that 49 CFR Part 192, contains various construction requirements

	covering problems of installation in a common trench in Subpart G and in §192.467 with respect to corrosion control. The standards do not specifically prohibit common trench installations, but they must meet all applicable requirements in Part 192. 2. Clarifies that Section 192.467(b) requires one or more insulating devices to be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Insulating devices are required only when the portion of pipeline being protected is electrically isolated to achieve the required level of cathodic protection. 3. Clarifies that if a pipeline is not required to have cathodic protection, §192.467(b) does not require the pipeline to have insulating devices. **Interpretation: PI-74-009 Date: February 02, 1974** Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465. **Interpretation: PI-72-030 Date: July 14, 1972** Clarifies that Section 192.467(a) does not apply to all gas distribution systems but is intended to apply to all new pipelines. Existing distribution systems are covered by Section 192.467(b), which requires insulation wherever electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Existing distribution lines must be cathodically protected only in areas in which active corrosion is found (Section 192.457(b)(3)). Electrical isolation of existing distribution lines is not required under all circumstances, but only where necessary to facilitate the application of corrosion control required by Section 192.457(b)(3). **Interpretation: PI-ZZ-085 Date: September 24, 1970** Clarifies that DOT jurisdiction would stop at the downstream side of the customer's meter and the "house line" would not be regulated.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary National Electrical Code (ANSI/NFPA 70- is latest incorporated revision per 192.7)
Guidance Information	1. Electrical isolation devices should not be installed in areas where a combustible atmosphere may exist unless suitable precautions are taken to prevent electrical arcing. Examples of such areas are: vaults, buildings, other enclosed areas, etc. 2. Usually these situations would be found during the field inspection or after accidents. Some precautionary measures might include the installation of grounding cells or polarization cells.
Examples of a Probable Violation or Inadequate Procedures	1. An insulating device is installed in an area where a combustible atmosphere is anticipated and no precautions are taken. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Operator’s procedure on insulating devices, maintenance records, photographs.
Other Special Notations	Exercise caution whenever entering into an area where a combustible atmosphere might be present. Air monitoring may be necessary in vaults, buildings and other enclosed areas before and during entry to ensure that a combustible, low-oxygen or other potentially dangerous atmosphere is not present.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.467(f)**
Section Title	**External corrosion control: Electrical isolation.**
Existing Code Language	Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.
Origin of Code	NGLPSA 1968
Last Amendment	[Amdt.192-33, 43 FR 39389, Sept. 5, 1978]
Interpretation Summaries	**Interpretation: PI-98-009 Date: November 10, 1998** 1. Clarifies the purpose of § 192.467(f), "close proximity" means near enough to the listed structures to reasonably expect that a lightning strike or fault current involving the structure might harm the pipeline's corrosion control system. Close proximity is not an absolute or minimum distance, and it could vary depending on site conditions. Under § 192.453, the distance must be determined by a person qualified in pipeline corrosion control methods who has knowledge of the circumstances. 2: Insufficient Information. 3: Clarifies that Section 192.467(f) does not specify a threshold voltage in connection with protective measures. This voltage would be determined by a person qualified in pipeline corrosion control methods. 4: Clarifies that Under § 192.467(f), the term "electrical transmission tower" is used in its ordinary sense to refer to tall aboveground steel structures that support cables used to transmit electricity over long distances. The term does not include poles that support cables used to distribute electricity throughout a community. 5: Clarifies that protection is required only against fault currents and lightning and does not include protecting the pipeline from induced currents. **Interpretation: PI-93-053 Date: August 19, 1993** 1. Clarifies that Section 192.467(a) requires each pipeline on which external corrosion control is required to be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit. The electrical interconnection must be designed and installed as a part of the cathodic protection system to enable the pipeline and other structures to be cathodically protected together. 2. Clarifies that Section 192.467(b) requires one or more insulating devices to be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Insulating devices are required only when the portion of pipeline being protected is electrically isolated to achieve the required level of cathodic protection. 3. Clarifies that if a pipeline is not required to have cathodic protection, §192.467(b) does not require the pipeline to have insulating devices.

	Interpretation: PI-75-001 Date: January 9, 1975 Clarifies that 192.457(b)(1) requires bare or ineffectively coated transmission lines installed before August 1, 1971, except for cast or ductile iron lines, be cathodically protected in accordance with Subpart I in areas in where active corrosion is found. 192.467(b)(1) is intended primarily for transmission lines traversing areas with heavy population. The requirements of section 192.457(b)(1) apply regardless of the population of the areas in which a transmission line is located. **Interpretation: PI-74-020 Date: March 18, 1974** Clarifies that 49 CFR Part 192, contains various construction requirements covering problems of installation in a common trench in Subpart G and in §192.467 with respect to corrosion control. The standards do not specifically prohibit common trench installations, but they must meet all applicable requirements in Part 192. **Interpretation: PI-74-009 Date: February 02, 1974** Clarifies that steel risers on plastic services must be coated and cathodically protected as required by Section 192.455 of Subpart I. Each service riser must be electrically insulated from other house piping as required by Section 192.467(b) and the level of protection must meet one or more of the criteria contained in Section 192.463. The frequency for monitoring the cathodic protection applied to service risers is covered by Section 192.465. **Interpretation: PI-72-030 Date: July 14, 1972** Clarifies that Section 192.467(a) does not apply to all gas distribution systems but is intended to apply to all new pipelines. Existing distribution systems are covered by Section 192.467(b), which requires insulation wherever electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Existing distribution lines must be cathodically protected only in areas in which active corrosion is found (Section 192.457(b)(3)). Electrical isolation of existing distribution lines is not required under all circumstances, but only where necessary to facilitate the application of corrosion control required by Section 192.457(b)(3). **Interpretation: PI-ZZ-085 Date: September 24, 1970** Clarifies that DOT jurisdiction would stop at the downstream side of the customer's meter and the "house line" would not be regulated.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	The operator must be aware of all electrical transmission tower footings, ground cables, or counterpoise that are in close proximity to its pipeline. A testing program must be in place to test for possible adverse effects of high power transmission lines and ground cables.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not protect its pipeline against damage from fault currents or lightning where necessary. 2. The operator did not take protective measures at an insulating device. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the*

	enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.
Examples of Evidence	1. Field checks, maintenance records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.469**
Section Title	**External corrosion control: Test stations.**
Existing Code Language	Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-4, 36 FR 12297, June 30, 1971, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]
Interpretation Summaries	**Interpretation: PI-85-009 Date: October 24, 1985** Clarifies that permanent potential monitoring test stations, placed throughout a steel gas distribution system which is completely welded (no couplings) and checked on a monthly basis, satisfy the annual "test for cathodic protection" requirement. If an operator tests at sufficient test stations per §192.469 and demonstrates compliance with §192.463, then the testing would also comply with the requirements of §192.465(a). **Interpretation: PI-ZZ-088 Date: August 4, 1983** Clarifies that if service lines are electrically continuous with mains, they may be used as test stations. Spacing of test stations along the pipeline system will vary widely depending upon the type of soil, moisture, quality of pipe coating, size of pipe, type of cathodic protection system, level of cathodic protection, etc. Whatever the number and spacing of test points along a cathodically protected pipeline, they must be adequate to show that the cathodic protection level along the entire length of *pipeline* meets the requirements of Section 192.463. With so many variables involved, the distance between test stations must be based on the judgment of a person qualified by experience and training in pipeline corrosion control methods for the specific installation and conditions.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator must have sufficient test stations where data is collected to demonstrate that its entire pipeline is cathodically protected. (A test station is the location designated by the operator on a pipeline or facility, where cathodic protection readings are taken.) Test stations for potential, current, or resistance measurements should be provided at sufficient locations to facilitate cathodic protection testing. Such locations may include, but not be limited to, the following: pipe casing installations, metallic structure crossings, isolating joints, waterway crossings, bridge crossings, valve stations, galvanic anode installations, road crossings, stray-current areas, and rectifier installations. Common industry practice is to install test leads and designate test stations at convenient locations along the ROW of a buried pipeline. This may include adding additional galvanic anodes, test stations, rectifiers and ground beds, and/or increasing the output of the rectifiers on

	either side of the area of low readings. 2. Close interval surveys not only confirm pipe-to-soil readings at the established test stations but also confirm the cathodic protection's effectiveness between the two test stations. This may be an indication that there are insufficient test stations. If the operator has had a corrosion leak or discovers that new corrosion is occurring, the operator may not have adequate cathodic protection and may not have an adequate number of test stations to effectively evaluate the system, or there may be an isolated shielding problem.
Examples of a Probable Violation or Inadequate Procedures	1. The operator does not have sufficient test stations to ensure that its entire pipeline is cathodically protected. 2. If pipe-to-soil data, corrosion leak history or in-line inspection data indicates that the operator does not have test stations at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection. 3. The operator has not repaired or replaced defective test leads when necessary to determine adequate cathodic protection. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Graphical representation of P/S readings vs. distance along a pipeline segment showing insufficient number of test stations and/or readings that do not meet the operator's documented criteria for cathodic protection. Maps showing locations of test stations.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.471(a)**
Section Title	**External corrosion control: Test leads.**
Existing Code Language	Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.
Origin of Code	NGPLSA 1968
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/ Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1 INSTALLATION METHODS Some acceptable methods for making test lead connections include the following: 1.1 Thermite welding. (a) Steel. Attachment of electrical leads directly to steel pipe by the thermite welding process using copper oxide and aluminum powder. The thermite welding charge should be limited to the manufacturers recommended cartridge size. 1.2 Solder connections. Attachment of electrical leads directly to steel pipe with the use of soft solders or other materials which do not involve temperatures exceeding those for soft solders. 1.3 Mechanical connections. Mechanical connections should remain secure and electrically conductive. 2 OTHER CONSIDERATIONS For convenience, conductors may be coded or permanently identified. Wire should be installed with slack and wrapped around the pipe to further secure the attachment from damage if they are pulled. 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. 3. ***Williston Basin Interstate Pipeline Company [3-2005-1008]*** **(June 21, 2007)** – Found that the operator failed to reconnect a test lead after discovering that it was broken during its annual survey. Having reason to believe that the level of cathodic protection in the area is adequate does not satisfy the regulation. If the operator had been able to demonstrate that it made a technically justified decision to discontinue

	testing at this station at the relevant time, there would not have been a violation. Without such a determination, the broken test lead reflects a lack of maintenance. CP
Examples of a Probable Violation or Inadequate Procedures	1. Test lead wire was not connected using a method to remain mechanically secured and electrically conductive. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Pictures, maintenance records, O&M Manual, operator's personnel statements
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.471(b)**
Section Title	**External corrosion control: Test leads.**
Existing Code Language	Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.
Origin of Code	NGPLSA 1968
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	The operator's procedures and/or test lead wire installation must not use a thermite welding charge that is greater than the manufacturers recommended cartridge size for the pipe to be welded.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not install a test lead wire so as to minimize stress concentration on the pipeline. 2. The thermite welding charge is greater than the manufacturers recommended cartridge size. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Pictures, maintenance records, O&M Manual, operator's personnel statements.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.471(c)**
Section Title	**External corrosion control: Test leads.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	The operator's procedures and/or test lead wire installation must coat bared areas of the pipeline and test lead wire after installation.
Examples of a Probable Violation or Inadequate Procedures	1. The test lead connection to the pipeline was not coated or was improperly coated. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Pictures, maintenance records, O&M Manual, operator's personnel statements
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.473(a)**
Section Title	**External corrosion control: Interference currents.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-4, 36 FR 12297, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]
Interpretation Summaries	**Interpretation: PI-ZZ-070 Date: November 15, 1979** This interpretation clarifies section 192.473 and states that at least 10% of an operator's affected pipeline must be monitored with a close interval survey during a calendar year. The interpretation also explains that section 192.473 requires an operator to monitor its own pipeline the beneficial and detrimental effects of stray currents; and lastly, it informs an operator that the operator is responsible for any and all stray current affects on any of its other below ground structures.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary NACE SP0169-2007 Appendix A
Guidance Information	1. Underground structures that might subject the pipeline system to stray currents include foreign pipelines, underground storage tanks, or other utility systems. Other potential stray current sources include direct current (DC) transit systems, DC mining operations, DC welding operations, and high voltage (AC or DC) electric transmission systems. 2. The operator must have a written plan to identify, test for, and minimize the detrimental effects of such currents. 3. Annual test station surveys are generally insufficient to determine whether stray currents are present on the pipeline. An operator, particularly of a pipeline in a congested area with a lot of other cathodically protected structures, will generally need to perform close-interval surveys or turn suspected foreign rectifiers on and off to obtain sufficient information to determine whether stray currents are present on the pipeline. The operator must then take action to mitigate the detrimental effects of the stray current. Mitigative actions may include the installation of an interference bond between the structures, the addition of magnesium anodes to bleed away the stray current, recoating selected portions of one or both of the structures, reverse current switches, etc.
Examples of a Probable Violation or Inadequate Procedures	1. The operator does not have a written program to minimize the detrimental effects of stray currents. 2. If there are potential sources of interference, the operator did not perform testing or take mitigative actions in accordance with its program, as necessary. *Depending on the circumstances, some of the examples listed in this section may be*

	inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.
Examples of Evidence	1. O & M manual. 2. Maintenance records.
Other Special Notations	Caution should be taken in areas of potentially high induced foreign currents, such as in overhead power corridors.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.473(b)**
Section Title	**External corrosion control: Interference currents.**
Existing Code Language	Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effect on existing adjacent underground metallic structures.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-4, 36 FR 12297, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]
Interpretation Summaries	**Interpretation: PI-ZZ-070 Date: November 15, 1979** This interpretation clarifies section 192.473 and states that at least 10% of an operator's affected pipeline must be monitored with a close interval survey during a calendar year. The interpretation also explains that section 192.473 requires an operator to monitor its own pipeline the beneficial and detrimental effects of stray currents; and lastly, it informs an operator that the operator is responsible for any and all stray current affects on any of its other below ground structures.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. When designing and installing a cathodic protection system, the operator should evaluate the potential for causing adverse effects on existing nearby structures. The operator's documentation should indicate that some effort was made to identify such structures and to perform testing, if necessary, after the installation to demonstrate that stray currents from the system are not adversely affecting any existing adjacent structures. If found to be, then the operator should cooperate with the owner of the foreign structure as necessary to mitigate the adverse effects. Mitigation measures may include galvanic anodes, bonds, coating, polarization cell, relocating pipeline or CP facilities. 2. In many areas of the country, particularly areas with a high density of pipelines or other underground facilities, coordinating committees may be active and provide a forum for cathodic protection users to meet and inform other members of its activities and to facilitate testing and mitigative measures.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not design and install its impressed current type cathodic protection system or galvanic anode system to minimize the detrimental effects of stray currents. 2. The operator did not perform any necessary post-installation testing on existing adjacent metallic structures. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Design documents and installation records. Cathodic protection records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.475(a)**
Section Title	**Internal corrosion control: General.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	**Interpretation: PI-ZZ-072 Date: November 19, 1998** This interpretation clarifies that "corrosive gas" is not defined in Part 192, in general, or in section 192.475, specifically. However, the interpretation explains that the term "corrosive material" is defined in the hazardous materials regulations [and not the pipeline safety regulations] under 49 CFR 173.136. This definition, which contains criteria for determining damage to human skin or the corrosion rate on steel or aluminum, is cross-referenced in the definition of "corrosive product" in PHMSA's hazardous liquid pipeline safety standards at 49 CFR 195.2. The definition [of "corrosive gas"] can be used as a guide (for an operator) to determine if a gas is corrosive, or not. **Interpretation: PI-ZZ-071 Date: August 5, 1983** This interpretation clarifies section 192.475 and states that the only regulatory limitation on the amount of hydrogen sulfide permitted in gas is 0.1 grain of hydrogen sulfide per 100 standard cubic feet requirement per Section 192.475(c), and explains that this limitation is only applicable to gas stored in pipe-type or bottle-type holders.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. Are there any indications that point out internal corrosion could be a problem? 2. Most transported gas is quality controlled by either a tariff or by contract. A record of the constituents in the gas can be obtained from the operator. Usually, the record will be a gas chromatograph. Operators are required to keep this record. 3. The operator should have a procedure to determine if the gas is corrosive. The procedure for identifying the factors that influence the formation of internal corrosion, including gas quality and operating parameters, in particular gas velocity and temperature. Special attention should be given to pipeline alignment features such as changes in elevation, low points, sharp bends that may contribute to internal corrosion by allowing condensates to settle out of the gas stream. Free water inside a pipeline can combine with carbon dioxide and hydrogen sulfide to form acids that cause serious damage to the internal surfaces of pipelines and their associated appurtenances. Microbiologically influenced corrosion (MIC) can also cause serious internal corrosion problems in pipelines that contain condensates. Bacterial colonies can form deposits on metal surfaces and produce organic acids that accelerate corrosion and cause localized pitting. 4. Some methods for monitoring internal corrosion are weight loss coupons,

	radiography, water chemistry tests, in-line inspection tools, and electrical, galvanic, resistance and hydrogen probes. Special attention should be given to specific conditions, including flow characteristics, pipeline location (especially drips, deadlegs, and sags,) which are on-line segments that are not cleaned by pigging or other methods. Internal corrosion is influenced by flow regime, pipeline location, operating temperature and pressure, water content, carbon dioxide and hydrogen sulfide content, oxygen, bacteria and sediment deposits. 5. Some locations from where periodic testing of liquids should be performed include pipeline drips, deadhead locations, low points and downstream of dehydration facilities, compressor stations, and metering and regulating stations. 6. In the case of horizontal barrel type drips using ERW pipe, if the pipe seam is located on the top side of the drip, this may help prevent accelerated corrosion along the pipe seam due to the retention of condensates. 7. If the operator prefers the use of cleaning pigs and in-line inspection (ILI) tools, the pipeline geometry should be constant and all direction changes should be accomplished using fitting to allow for smooth movement of the pigs. If liquids and solids are removed during the cleaning pigging operation they should be tested for corrosive properties. 8. The gas stream should be tested for oxygen, carbon dioxide, hydrogen sulfide and water content. The liquid sample should be tested for pH levels, iron, chlorides, and bacteria. 9. ***West Texas Gas, Inc. [4-2004-1007]*** **(September 13, 2006) –** Found that the operator is obligated to ensure that the gas transported is not corrosive. Confirming the quality of the gas by telephone calls with the suppliers and physical inspections of pipe do not satisfy this requirement. CO
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not investigate the corrosive effect of the gas on the pipeline. 2. If corrosive gas has been identified, the operator did not take steps to minimize internal corrosion. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's O & M procedure, tariff, contract.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.475(b)**
Section Title	**Internal corrosion control: General.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	**Interpretation: PI-ZZ-072 Date: November 19, 1998** This interpretation clarifies that "corrosive gas" is not defined in Part 192, in general, or in section 192.475, specifically. However, the interpretation explains that the term "corrosive material" is defined in the hazardous materials regulations [and not the pipeline safety regulations] under 49 CFR 173.136. This definition, which contains criteria for determining damage to human skin or the corrosion rate on steel or aluminum, is cross-referenced in the definition of "corrosive product" in PHMSA's hazardous liquid pipeline safety standards at 49 CFR 195.2. The definition [of "corrosive gas"] can be used as a guide (for an operator) to determine if a gas is corrosive, or not. **Interpretation: PI-ZZ-071 Date: August 5, 1983** This interpretation clarifies section 192.475 and states that the only regulatory limitation on the amount of hydrogen sulfide permitted in gas is 0.1 grain of hydrogen sulfide per 100 standard cubic feet requirement per Section 192.475(c), and explains that this limitation is only applicable to gas stored in pipe-type or bottle-type holders.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. Any time a pipe section (either distribution or transmission) is removed or cut, an inspection for corrosion inside the pipe must be performed. If corrosion is found on the inside surface of the adjacent pipeline then remaining wall strength calculations should be performed and the line segment derated, replaced or repaired according to the extent of internal corrosion found. If internal corrosion is found, the operator must have a program for mitigation.
Examples of a Probable Violation or Inadequate	1. The operator does not have records to show that an internal inspection of a removed section of pipe occurred. 2. Internal corrosion was found and the operator did not investigate to determine the extent of the internal corrosion present on adjacent pipe.

Procedures	3. The operator did not replace corroded pipe as required. 4. Internal corrosion was found and the operator did not take steps to minimize the internal corrosion. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. O & M manual. 2. Maintenance records. 3. Photographs.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.475(c)**
Section Title	**Internal corrosion control: General.**
Existing Code Language	Gas containing more than 0.25 grain of hydrogen sulfide per 100 standard cubic feet (5.8 milligrams/m3) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-85 , 63 FR 37500, July 13, 1998]
Interpretation Summaries	**Interpretation: PI-ZZ-072 Date: November 19, 1998** This interpretation clarifies that “corrosive gas” is not defined in Part 192, in general, or in section 192.475, specifically. However, the interpretation explains that the term “corrosive material” is defined in the hazardous materials regulations [and not the pipeline safety regulations] under 49 CFR 173.136. This definition, which contains criteria for determining damage to human skin or the corrosion rate on steel or aluminum, is cross-referenced in the definition of “corrosive product” in PHMSA’s hazardous liquid pipeline safety standards at 49 CFR 195.2. The definition [of “corrosive gas”] can be used as a guide (for an operator) to determine if a gas is corrosive, or not. **Interpretation: PI-ZZ-071 Date: August 5, 1983** This interpretation clarifies section 192.475 and states that the only regulatory limitation on the amount of hydrogen sulfide permitted in gas is 0.1 grain of hydrogen sulfide per 100 standard cubic feet requirement per Section 192.475(c), and explains that this limitation is only applicable to gas stored in pipe-type or bottle-type holders.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. Pipe type and bottle type holders are not often encountered on pipelines or distribution systems. If they are found the regulations restrict the H2S content of the gas to 0.25 grain or less per 100 cubic feet.
Examples of a Probable Violation or Inadequate Procedures	1. Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet at standard conditions is stored in pipe-type or bottle-type holders. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. O & M procedure, gas sampling analysis, tariff, contract.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.476(a)**
Section Title	**Internal corrosion control: Design and construction of transmission line.**
Existing Code Language	(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 constriction 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.
Origin of Code	NGPLSA 1968
Last Amendment	[72 FR 20059, Apr. 23, 2007]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. During design and construction of replacement segments or new pipeline construction, the operator must configure the system to reduce liquid collection. The operator's documentation, records, reports or drawings should indicate that some effort was made to reduce or eliminate liquid holdup within transmission pipeline systems. 2. This regulation requires operators to use design and construction features in new and replaced gas transmission pipelines to reduce the risk of internal corrosion. This regulation also requires that whenever an operator changes the configuration of its pipeline, the operator must consider and address the impact those changes will have on the risk of internal corrosion in its existing downstream pipeline. The intent of this regulation is to reduce the risk of internal corrosion and related pipeline failures by reducing the potential for accumulation of liquids, design and construct new pipelines with effective liquid removal features; and design and construct pipelines that allow for the use of corrosion control monitoring devices at locations

	susceptible to internal corrosion. It is also the intent of this regulation to ensure that operators are engaged in operation and maintenance practices that address internal corrosion. This regulation does not apply to offshore pipelines. Nor does this regulation apply to any pipeline installed, or line pipe, valve fitting or other line component replaced before May 23, 2007.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not design or construct replacement piping, valves, fittings or other components to reduce or eliminate liquid collection within a transmission pipeline system. 2. The operator did not design the pipeline with an effective method for removing liquids where the configuration allows liquids to collect. 3. The operator did not design the pipeline to allow for the use of devices to monitor for internal corrosion at locations with significant potential for internal corrosion. 4. An operator has designed and constructed its pipeline without including features that: (a). Reduce the risk that liquids will collect in the line; (b). Have effective liquid removal features whenever the configuration would allow liquids to collect; and (c). Does not allow for the use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's procedures, drawings, design or construction records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.476(b)**
Section Title	**Exceptions to Applicability**
Existing Code Language	(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.
Origin of Code	NGPLSA 1968
Last Amendment	[72 FR 20059, Apr. 23, 2007]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	
Examples of a Probable Violation or Inadequate Procedures	
Examples of Evidence	1. Operator’s procedures, drawings, design or construction records
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.476(c)**
Section Title	**Change to existing transmission line.**
Existing Code Language	(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.
Origin of Code	NGPLSA 1968
Last Amendment	[72 FR 20059, Apr. 23, 2007]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. This regulation requires operators to use design and construction features in new and replaced gas transmission pipeline to reduce the risk of internal corrosion. This regulation also requires that whenever an operator changes the configuration of its pipeline, the operator must consider and address the impact those changes will have on the risk of internal corrosion in its existing downstream pipeline. 2. The intent of this regulation is to reduce the risk of internal corrosion and related pipeline failures by reducing the potential for accumulation of liquids, design and construct new pipelines with an effective liquid removal features; and design and construct pipelines that will allow for the use of corrosion control monitoring devices at location susceptible to internal corrosion. It is also the intent of this regulation to ensure that operators are engaged in operation and maintenance practices that address internal corrosion. 3. This regulation does not apply to offshore pipelines. Nor does this regulation apply to any pipeline installed, or line pipe, valve fitting or other line component replaced before May 23, 2007.
Examples of a Probable Violation or Inadequate Procedures	1. The operator changed the configuration of a transmission line and has not evaluated the impact of the change on internal corrosion risk to the downstream portion of the existing pipeline. 2. The operator must provide for the removal of liquids and monitoring of internal corrosion as appropriate.

	3. An operator changes the configuration of its existing pipeline, but fails to evaluate the impact of that change on the downstream portion of its existing onshore transmission line for the risk of internal corrosion; and the operator does not provide for the removal of liquids and use of internal corrosion monitoring devices. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator's procedures, drawings, design or construction records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.476(d)**
Section Title	**Records**
Existing Code Language	(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.
Origin of Code	NGPLSA 1968
Last Amendment	[72 FR 20059, Apr. 23, 2007]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. If the operator can demonstrate why incorporating the design features is impracticable or unnecessary, an operator may provide written procedures supported by as-built drawings or other construction records. 2. This regulation requires operators to use design and construction features in new and replaced gas transmission pipeline to reduce the risk of internal corrosion. This regulation also requires that whenever an operator changes the configuration of its pipeline, the operator must consider and address the impact those changes will have on the risk of internal corrosion in its existing downstream pipeline. 3. The intent of this regulation is to reduce the risk of internal corrosion and related pipeline failures by reducing the potential for accumulation of liquids, design and construct new pipelines with an effective liquid removal features; and design and construct pipelines that will allow for the use of corrosion control monitoring devices at location susceptible to internal corrosion. It is also the intent of this regulation to ensure that operators are engaged in operation and maintenance practices that address internal corrosion. 4. This regulation does not apply to offshore pipelines. Nor does this regulation apply to any pipeline installed, or line pipe, valve fitting or other line component replaced before May 23, 2007.
Examples of a Probable Violation or Inadequate Procedures	1. An operator has not maintained records demonstrating compliance with this section. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Operator’s procedures, drawings, design or construction records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.477**
Section Title	**Internal corrosion control: Monitoring.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-4, 36 FR 12297, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin: ADB-00-02 Internal Corrosion in Gas Transmission Pipelines** The Office of Pipeline Safety (OPS) is issuing this bulletin to owners and operators of natural gas transmission pipeline systems to advise them to review their internal corrosion monitoring programs and operations. Operators should consider factors that influence the formation of internal corrosion, including gas quality and operating parameters. Operators should give special attention to pipeline alignment features that may contribute to internal corrosion by allowing condensates to settle out of the gas stream.
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. Review the operator's history, coupon and other monitoring test data, and internal inspection records to determine whether internal corrosion has occurred. If so, the gas being transported is corrosive and the operator should be taking active measures to monitor and mitigate the internal corrosion. 2. ***Puget Sound Energy, Inc. [5-2002-1001]*** **(June 16, 2004) –** Found that the presence of water vapor in the gas stream, visible free-standing water in a slug catcher, the failure to monitor water levels, and to account for possible trace contaminants in the gas stream is sufficient evidence that the operator should have been monitoring for internal corrosion. Processing natural gas to make it "pipeline quality" does not ensure total removal of trace contaminants that can cause corrosion. CO
Examples of a Probable Violation or Inadequate Procedures	1. Corrosive gas is being transported and coupons or other suitable means are not used to determine the effectiveness of internal corrosion control. 2. Method of monitoring internal corrosion is not performed two times each calendar year or at periods exceeding 7 ½ months. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not*

	a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.
Examples of Evidence	1. a. Documentation showing the transported gas is corrosive, including laboratory analysis of gas sample showing that it is corrosive, for example, that it contains hydrogen sulfide, or operator's records showing leaks caused by internal corrosion. b. Documentation showing that coupons or other suitable means are not being used. Investigator's or operator's statement indicating coupons or other means are not being used. 2. The internal corrosion monitoring program does not have all analytical and operational data to evaluate such program.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.479(a)**
Section Title	**Atmospheric corrosion control; General.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-4, 36 FR 12297, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-93, 68 53895, Sept. 15, 2003]
Interpretation Summaries	**Interpretation: PI-ZZ-092 Date: February 14, 2003** This interpretation clarifies that Section 192.481 states that operators shall evaluate each onshore pipeline that is exposed to the atmosphere at least every three years and take remedial action whenever necessary to maintain protection against atmospheric corrosion; however, this section does not exempt pipelines that are in areas initially determined to have a noncorrosive atmosphere under § 192.479, but rather requires periodic evaluation of all pipelines exposed to the atmosphere. Therefore, all pipeline facilities exposed to the atmosphere must be periodically monitored for evidence of atmospheric corrosion. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.479(b) does not allow operators to exercise discretion in applying protection against corrosion. Operators must apply the prescribed protective measures to all corrosion covered by this standard. **Interpretation: PI-91-013 Date: May 23, 1991** This interpretation clarifies section 192.479 and states that surface rust or passive surface oxidation caused by atmospheric corrosion would subject the pipeline to the requirements of §192.479(b) if the corrosion is deteriorating the pipeline, such as pitting. Moreover, the interpretation states that section 192.479(a) requires that a pipeline be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion unless it can be shown that a corrosive atmosphere does not exist; e.g., showing that passive surface oxidation does not deteriorate the pipeline. **Interpretation: PI-74-003 Date: January 24, 1974** This interpretation clarifies that there are no cathodic protection requirements for aboveground piping; however, the operator must comply with appropriate portions of Section 192.479 of Subpart I of the Federal standards to protect against atmospheric corrosion.

Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards; Glossary
Guidance Information	1. A pipeline exposed to the atmosphere is a pipeline that is not buried or submerged in an electrolyte such as soil or seawater. 2. Atmospheric Corrosion is an area of metal loss due to general corrosion, localized corrosion pitting, or peeling scale on the steel surface that has damaged the pipe. Surface oxide is corrosion and if allowed to continue may affect the safe operation of the pipeline at some point in the future. Oxidation (or "light surface oxide") can be defined as the slow rusting of pipe which is not yet considered to be atmospheric corrosion because there is no evidence of metal loss at this time.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere unless the operator has demonstrated by test, investigation or experience that corrosion will: (a). only be a light surface oxide (b). not affect the safe operation of the pipeline. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Pictures, operator's personnel statements, maintenance records, pit depth measurement, documented evidence of pipe wall loss.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.479(b)**
Section Title	**Atmospheric corrosion control; General.**
Existing Code Language	Coating material must be suitable for the prevention of atmospheric corrosion.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-4, 36 FR 12297, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-93, 68 53895, Sept. 15, 2003]
Interpretation Summaries	**Interpretation: PI-ZZ-092 Date: February 14, 2003** This interpretation clarifies that Section 192.481 states that operators shall evaluate each onshore pipeline that is exposed to the atmosphere at least every three years and take remedial action whenever necessary to maintain protection against atmospheric corrosion; however, this section does not exempt pipelines that are in areas initially determined to have a noncorrosive atmosphere under § 192.479, but rather requires periodic evaluation of all pipelines exposed to the atmosphere. Therefore, all pipeline facilities exposed to the atmosphere must be periodically monitored for evidence of atmospheric corrosion. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.479(b) does not allow operators to exercise discretion in applying protection against corrosion. Operators must apply the prescribed protective measures to all corrosion covered by this standard. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-91-013 Date: May 23, 1991** This interpretation clarifies section 192.479 and states that surface rust or passive surface oxidation caused by atmospheric corrosion would subject the pipeline to the requirements of §192.479(b) if the corrosion is deteriorating the pipeline, such as pitting. Moreover, the interpretation states that section 192.479(a) requires that a pipeline be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion unless it can be shown that a corrosive atmosphere does not exist; e.g., showing that passive surface oxidation does not deteriorate the pipeline. **Interpretation: PI-74-003 Date: January 24, 1974** This interpretation clarifies that there are no cathodic protection requirements for aboveground piping; however, the operator must comply with appropriate portions of Section 192.479 of Subpart I of the Federal standards to protect against atmospheric corrosion.

Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. Typical coating materials are non-conductive paints, coatings, or jackets which will isolate the metal from the atmosphere and are suitable for the contaminants in the atmosphere.
Examples of a Probable Violation or Inadequate Procedures	1. The coating material is unsuitable for the prevention of atmospheric corrosion. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Pictures, operator’s personnel statements, purchase orders, specifications.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.479(c)**
Section Title	**Atmospheric corrosion control; General.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-4, 36 FR 12297, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-93, 68 53895, Sept. 15, 2003]
Interpretation Summaries	**Interpretation: PI-ZZ-092 Date: February 14, 2003** This interpretation clarifies that Section 192.481 states that operators shall evaluate each onshore pipeline that is exposed to the atmosphere at least every three years and take remedial action whenever necessary to maintain protection against atmospheric corrosion; however, this section does not exempt pipelines that are in areas initially determined to have a noncorrosive atmosphere under § 192.479, but rather requires periodic evaluation of all pipelines exposed to the atmosphere. Therefore, all pipeline facilities exposed to the atmosphere must be periodically monitored for evidence of atmospheric corrosion. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.479(b) does not allow operators to exercise discretion in applying protection against corrosion. Operators must apply the prescribed protective measures to all corrosion covered by this standard. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-91-013 Date: May 23, 1991** This interpretation clarifies section 192.479 and states that surface rust or passive surface oxidation caused by atmospheric corrosion would subject the pipeline to the requirements of §192.479(b) if the corrosion is deteriorating the pipeline, such as pitting. Moreover, the interpretation states that section 192.479(a) requires that a pipeline be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion unless it can be shown that a corrosive atmosphere does not exist; e.g., showing that passive surface oxidation does not deteriorate the pipeline. **Interpretation: PI-74-003 Date: January 24, 1974** This interpretation clarifies that there are no cathodic protection requirements for aboveground piping; however, the operator must comply with appropriate portions of Section 192.479 of Subpart I of the Federal standards to protect against atmospheric corrosion.

Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. "Light surface oxide" is general oxidation of the metal where there is no associated loss of metal. Some corrosion experts consider a light surface oxide to be protective to the metal surface. 2. The exceptions do not include offshore splash zones (where tides and wave actions intermittently impact the pipe) and soil-to-air interfaces (where the pipe first leaves the soil and is exposed to the atmosphere. These areas are critical because of the transient conditions and must be protected from atmospheric corrosion. Protection is typically accomplished by ensuring that the pipe is coated and painted several inches (or feet, in the offshore case) above and below these interfaces.
Examples of a Probable Violation or Inadequate Procedures	1. The operator has no tests, investigations, or demonstrated experience that unprotected pipe exposed to the atmosphere does not require coating or painting. 2. The operator did not provide protection to offshore splash zones and/or soil-to-air interfaces. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Pictures, operator's personnel statements, records, documented evidence of pipe wall loss at interfaces.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.481(a)**
Section Title	**Atmospheric corrosion control: Monitoring**
Existing Code Language	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

Origin of Code	NGPLSA 1968
Last Amendment	Amdt. 192–93, 68 FR 53895, Sept. 15, 2003
Interpretation Summaries	**Interpretation: PI-ZZ-092 Date: February 14, 2003** This interpretation clarifies that Section 192.481 states that operators shall evaluate each onshore pipeline that is exposed to the atmosphere at least every three years and take remedial action whenever necessary to maintain protection against atmospheric corrosion; however, this section does not exempt pipelines that are in areas initially determined to have a noncorrosive atmosphere under § 192.479, but rather requires periodic evaluation of all pipelines exposed to the atmosphere. Therefore, all pipeline facilities exposed to the atmosphere must be periodically monitored for evidence of atmospheric corrosion. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.481 does not allow operators to exercise discretion in applying protection against corrosion. Operators must apply the prescribed protective measures to all corrosion covered by this standard. **Interpretation: PI-93-035 July 15, 1993** This interpretation clarifies that customer meter sets are part of service lines, and that the sets are subject to the same inspection requirements as service lines; and include monitoring for atmospheric corrosion under §192.481. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-91-03 Date: May 23, 1991** This interpretation clarifies that §192.481 requires pipelines that are exposed to the atmosphere be monitored for atmospheric corrosion.

	Interpretation: PI-74-003 Date: January 24, 1974 This interpretation clarifies that there are no cathodic protection requirements for aboveground piping; however, the operator must comply with appropriate portions of Section 192.481 of Subpart I of the Federal standards to protect against atmospheric corrosion.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator must have procedures specifying the required time intervals for inspecting all aboveground piping facilities, and subsequent inspection and maintenance records meeting the stated intervals.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not identify all above ground piping or reevaluate each pipeline that is exposed to the atmosphere, at least once every 3 calendar years but with intervals not exceeding 39 months for onshore pipeline and at least once each calendar year but with intervals not exceeding 15 months for offshore pipelines. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Pictures, maintenance records, pit measurements, pipe wall measurements, O&M Manual, operator's personnel statements.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.481(b)**
Section Title	**Atmospheric corrosion control: Monitoring**
Existing Code Language	During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under dis-bonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]
Interpretation Summaries	**Interpretation: PI-ZZ-092 Date: February 14, 2003** This interpretation clarifies that Section 192.481 states that operators shall evaluate each onshore pipeline that is exposed to the atmosphere at least every three years and take remedial action whenever necessary to maintain protection against atmospheric corrosion; however, this section does not exempt pipelines that are in areas initially determined to have a noncorrosive atmosphere under § 192.479, but rather requires periodic evaluation of all pipelines exposed to the atmosphere. Therefore, all pipeline facilities exposed to the atmosphere must be periodically monitored for evidence of atmospheric corrosion. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.481 does not allow operators to exercise discretion in applying protection against corrosion. Operators must apply the prescribed protective measures to all corrosion covered by this standard. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that customer meter sets are part of service lines, and that the sets are subject to the same inspection requirements as service lines; and include monitoring for atmospheric corrosion under §192.481. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-91-03 Date: May 23, 1991** This interpretation clarifies that §192.481 requires pipelines that are exposed to the atmosphere be monitored for atmospheric corrosion.

<table>
<tr><td></td><td>Interpretation: PI-74-003 Date: January 24, 1974

This interpretation clarifies that there are no cathodic protection requirements for aboveground piping; however, the operator must comply with appropriate portions of Section 192.481 of Subpart I of the Federal standards to protect against atmospheric corrosion.</td></tr>
<tr><td>Advisory Bulletin/Alert Notice Summaries</td><td></td></tr>
<tr><td>Other Reference Material & Source</td><td>Industry Standards, Glossary</td></tr>
<tr><td>Guidance Information</td><td>1. Operators should define in their O&M procedures and inspection records which areas require particular attention. The most difficult areas to inspect may be under pipe supports and under thermal insulation. Atmospheric corrosion may be concealed under dis-bonded coatings.
2. For onshore pipelines, the operator should give particular attention to corrosion at soil-to-air interfaces, under thermal insulation, under dis-bonded coatings, and at pipe supports. For offshore pipelines, the operator should give particular attention to corrosion under dis-bonded coatings, in splash zones, at pipe supports, and at wall and deck penetrations.
Corrosion Under Thermal Insulation – Note: Operators need not completely remove all thermal insulation to satisfy the monitoring requirements for atmospheric corrosion. If an operator does not remove all insulation from thermally insulated pipe, the operator should identify avenues allowing moisture intrusion into the pipe/insulation system, pipe orientation or junctions between insulated and non-insulated pipe and components.
3. The Operator’s O&M procedures should also provide details on paying particular attention to corrosion under thermal insulation.
4. The standards contained in Part 192 and incorporated by reference do not include specific guidance on paying particular attention to corrosion under thermal insulation. However, the following standards (not incorporated by reference) do provide such guidance, and are designed to minimize the deleterious effects of corrosion under thermal insulation. The inspector is encouraged to become familiar with these standards. The inspector must also remain mindful that these standards are not incorporated by reference and should not be relied on to cite an operator for violations of the pipeline safety standard. The following standards are provided as information to provide operators and pipeline inspectors with reference standards that discuss corrosion under insulation. The standards are:
• API 570 (Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems); and API 574 (Inspection Practices for Piping System Components)
• Inspectors are also encouraged to become familiar with</td></tr>
</table>

	standard, API 510 **(Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration).** This standard is incorporated by reference in Part 195. 5. The operator should specify and employ an adequate corrosion under thermal insulation evaluation system based on measurement or visual observation that enable the operator to properly evaluate the status of the piping system. An evaluation system of “visual observation” may be sufficient in those instances where the operator is able to observe visually that the pipeline coating is in “excellent condition”, or that “some surface rust” is observed, as well as the obvious “need for coating repair”, etc. However, in those instances where a “visual observation” may not be sufficient, such as in instances of “pitting” or similar flaws, which may dictate a quantitative evaluation, the operator should perform a more in-depth analysis, and rely on more measureable techniques, such as the use of a “pit gauge” to determine if the integrity of the pipe is threatened at the operating pressure. The operator should record the results of its examination as required in the written procedures. 6. External inspection of insulated piping systems should include a review of the insulation system for conditions that could lead to corrosion under thermal insulation and/or indicate signs of ongoing corrosion under thermal insulation. 7. The extent of corrosion under thermal insulation inspection program may vary depending on the local climate. Marine locations in warmer areas may require a very active program, whereas cooler, drier, mid-continent locations may not need as extensive a program. Sources of moisture can include rain, water leaks, condensation, deluge systems, and cooling towers. 8. General considerations for inclusion in the Operator’s O&M procedures for corrosion under thermal insulation inspections include: a. The Inspection interval between corrosion under thermal insulation inspections at least once every 3 calendar years, but not exceeding 39 months b. Criteria for removing insulation, if necessary, based on the inspection findings c. Criteria for remediating findings d. Requirements for documenting the inspection
	9. Piping System considerations for inclusion in the Operator’s O&M procedures for corrosion under thermal insulation inspections (Systems that are potentially more susceptible to corrosion under thermal insulation) include: a. Piping systems with deteriorated insulation, coatings, and/or wrappings; bulges or staining of the insulation or jacketing system or missing bands (bulges can indicate corrosion product buildup) b. Dead-legs and attachments that protrude from insulated piping and operate at a different temperature than the operating temperature of the active line c. Carbon steel piping systems, including ones insulated for

	personnel protection, operating between 10 °F and 350 °F; corrosion under thermal insulation is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture d. Carbon steel piping systems which normally operate in service above 350 °F, but are in intermittent service e. Those piping systems exposed to mist over-spray f. Those piping systems exposed to steam vents g. Those piping systems exposed to deluge systems h. Those piping systems subject to process spills or ingress of moisture or acid vapors i. Austenitic stainless steel piping systems operating between 120 °F and 400 °F (susceptible to chloride SCC) 10. Location considerations for inclusion in the Operator's O&M procedures for corrosion under thermal insulation inspections a. All penetrations or breaches in the insulation jacketing systems, such as: i. vents, drains ii. pipe hangers and other supports iii. valves and fittings (irregular insulation surfaces) iv. bolt-on pipe shoes b. Damaged insulation at higher plant or piping elevations that may result in corrosion under thermal insulation at lower areas remote from the damage c. Termination of insulation at flanges and other piping components d. Damaged or missing insulation jacketing e. Insulation jacketing seams located on the top of horizontal piping or improperly lapped or sealed insulation jacketing f. Caulking which has hardened, separated, or is missing g. Low points in piping systems that have a known breach in the insulation system, including low points in long unsupported piping runs h. Particular attention should be given to locations where insulation plugs have been removed to permit piping thickness measurements on insulated piping. These plugs should be promptly replaced and sealed. Several types of removable plugs are commercially available that permit inspection and identification of inspection points for future reference
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not give particular attention to pipe and apply remedial actions at soil-to-air interfaces, under thermal insulations, under dis-bonded coatings, at pipe supports, in splash zones, at deck penetrations and in spans over water when performing inspections of aboveground facilities. ***Corrosion Under Thermal Insulation –*** 2. Failure to specify a planned approach by which the operator can determine the areas of corrosion under thermal insulation.

	3. Failure to identify the piping and components under insulation that may be vulnerable to corrosion under thermal insulation. The operator should identify this information in its O&M manual, or alternatively, document this information on a form, and make reference in its O&M manual as to where the form is located, such that the information may be reviewed by the PHMSA inspector upon request. 4. Failure to provide adequate and ample observation points to properly assess the insulated system as a whole and to identify high risk areas for corrosion under thermal insulation. 5. If operator does not remove all insulation from thermally insulated pipe, failure to identify avenues allowing moisture intrusion into the pipe/insulation system, pipe orientation or junctions between insulated and non-insulated pipe and components. 6. Failure to specify and employ an adequate corrosion under thermal insulation evaluation system based on measurement or visual observation that enables the operator to properly evaluate the status of the piping system. The operator should record the results of its examination as required in the written procedures. 7. Failure to provide records of the corrosion under thermal insulation monitoring, which demonstrate the absence of corrosion under thermal insulation, or the evaluation status of corrosion under thermal insulation at each designated test point in the system. These records should be readily available, and the operator should be in position to produce such records upon request by the pipeline inspector. 8. Failure to specify and follow prescribed actions (i.e. monitoring, pipe, coating, etc.) on a thermally insulated piping system as specified in the Operator's O&M manual to remediate any corrosion under thermal insulation discovered – this would also include specifying a timeline for which those prescribed actions will be performed. Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.
Examples of Evidence	1. Pictures, maintenance records, pit measurements, pipe wall measurements, O&M Procedures Manual, operator's personnel statements.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.481(c)**
Section Title	**Atmospheric corrosion control: Monitoring**
Existing Code Language	If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by Sec.192.479.
Origin of Code	NGPLS968
Last Amendment	Amdt. 192-93, 68 FR5395, Sept. 15, 2003 (Waivers)
Interpretation Summaries	**Interpretation: PI-ZZ-092 Date: February 14, 2003** This interpretation clarifies that Section 192.481 states that operators shall evaluate each onshore pipeline that is exposed to the atmosphere at least every three years and take remedial action whenever necessary to maintain protection against atmospheric corrosion; however, this section does not exempt pipelines that are in areas initially determined to have a noncorrosive atmosphere under § 192.479, but rather requires periodic evaluation of all pipelines exposed to the atmosphere. Therefore, all pipeline facilities exposed to the atmosphere must be periodically monitored for evidence of atmospheric corrosion. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.481 does not allow operators to exercise discretion in applying protection against corrosion. Operators must apply the prescribed protective measures to all corrosion covered by this standard. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that customer meter sets are part of service lines, and that the sets are subject to the same inspection requirements as service lines; and include monitoring for atmospheric corrosion under §192.481. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-91-03 Date: May 23, 1991** This interpretation clarifies that §192.481 requires pipelines that are exposed to the atmosphere be monitored for atmospheric corrosion. **Interpretation: PI-74-003 Date: January 24, 1974** This interpretation clarifies that there are no cathodic protection requirements for aboveground piping; however, the operator must comply with appropriate portions of Section 192.481 of Subpart I of the Federal standards to protect against atmospheric corrosion.
Advisory Bulletin/Alert Notice Summaries	

Other Reference Material & Source	Industry Standards
Guidance Information	1. If the operator identified areas of atmospheric corrosion during an inspection, those areas must be protected before the next scheduled inspection. If corrosion is found that might jeopardize the integrity of the pipeline prior to the next scheduled inspection, then more prompt remedial action may be required under §192.485 or §192.487.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not protect areas of atmospheric corrosion found during an inspection before the operator's next scheduled inspection. 2. The operator did not repair or replace corroded pipe or components in accordance with §192.485 or §192.487, if necessary. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Pictures, maintenance records, O&M Procedures Manual, operator's personnel statements.
Other Special Notations	Inspectors should exercise caution if areas of severe atmospheric corrosion are discovered.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.483(a)**
Section Title	**Remedial measures: General.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	
Interpretation Summaries	**Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.483 does not allow operators to exercise discretion in applying protection against corrosion. Operators must apply the prescribed protective measures to all corrosion covered by this standard. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489**.**
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. When a metallic segment of a pipeline is installed, the replaced segment must have a properly prepared surface with an external protective coating that meets the requirements of 192.461. 2. Distribution systems: On bare steel pipe, replacement pipe must be coated, cathodically protected, electrically isolated and monitored on an annual basis. (Depends on length of the pipe, less than 100 feet, it can be monitored on a 10-year cycle). All the replaced pipeline segments must be provided with an external protective coating according to the operator’s material specifications. The replaced segments must have a satisfactory level of cathodic protection (see 192.465 for discussion on cathodic protection criteria).

Examples of a Probable Violation or Inadequate Procedures	1. The operator did not install properly coated replacement pipe. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.483(b)**
Section Title	**Remedial measures: General.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	
Interpretation Summaries	**Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.483 does not allow operators to exercise discretion in applying protection against corrosion. Operators must apply the prescribed protective measures to all corrosion covered by this standard. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The replaced segments must have a satisfactory level of cathodic protection (see 192.463 for cathodic protection criteria) and be monitored in accordance with 192.465(a).
Examples of a Probable Violation or Inadequate Procedures	1. A segment of buried or submerged pipe that replaced a segment of pipe because of external corrosion is not cathodically protected in accordance with subpart I. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement*

	Procedures provides guidance on selecting the appropriate enforcement action.
Examples of Evidence	1. O&M Manual, Maintenance records showing lack of proper coating and cathodic protection. Pictures, operator’s personnel statements.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.483(c)**
Section Title	**Remedial measures: General.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	
Interpretation Summaries	**Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.483 does not allow operators to exercise discretion in applying protection against corrosion. Operators must apply the prescribed protective measures to all corrosion covered by this standard. **Interpretation: PI-93-035 Date: July 15, 1993** This interpretation clarifies that section 192.457(b) applies to certain buried or submerged pipelines installed before August 1, 1971. The standard requires operators to cathodically protect areas of continuing corrosion that unless controlled could become detrimental to public safety. The interpretation further clarifies that §§192.479(b), 192.481, and 192.483 do not allow operators to exercise discretion in applying protection against corrosion, and that Operators must apply the prescribed cathodic protection measures covered by these standards. **Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The replaced segments must have a satisfactory level of cathodic protection (see 192.463 for cathodic protection criteria).
Examples of a Probable Violation or Inadequate Procedures	1. A segment of buried or submerged pipe, other than cast iron or ductile iron pipe, that is repaired because of external corrosion is not cathodically protected in accordance with subpart I. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement*

	Procedures provides guidance on selecting the appropriate enforcement action.
Examples of Evidence	1. O&M Manual, Maintenance records showing lack of proper coating and cathodic protection. Pictures, operator's personnel statements.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.485(a)**
Section Title	**Remedial measures: Transmission lines.**
Existing Code Language	**General corrosion.** Each segment of transmission line 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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt 192-88, 64 FR 69660, Dec 14, 1999]
Interpretation Summaries	**Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489**.** **Interpretation: PI-ZZ-093 Date: April 20, 1972** This interpretation clarifies that Section 192.485 gives the operator two choices when an area of general corrosion causes reduced wall thickness: (1) Replace the generally corroded segment of pipe; or (2) Reduce the operating pressure commensurate with the strength of the remaining pipe wall thickness.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator should have all the records on its replaced pipeline segments, pipeline repairs, and reduction of pipeline pressures. 2. The operator should have a procedure for calculating the strength of the pipeline based on actual remaining wall thickness and it may be determined by ASME/ANSI B31G or PR 3-805 (RSTRENG disk).
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not repair or replace a generally corroded segment of pipe. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	As-builts, operator repair records, internal inspection survey reports, exposed pipe inspection reports, or pictures.
Other Special Notations	Reference section 192.463(a) for CP criterion used. The reporting requirement at section 191.23(a)(1) Reporting safety-related conditions, where operators shall – with noted exceptions – file a SRCR for pipelines (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, where **general corrosion** has reduced the wall thickness to less than that required for the maximum allowable operating pressure (of its pipeline). Also note: Per SRCR requirements at section 191.25(a) Filing safety-related condition reports, each report of a safety-related condition under section 191.23(a) must be filed (received by the Associate Administrator, OPS) in writing within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.485(b)**
Section Title	**Remedial measures: Transmission lines.**
Existing Code Language	**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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt 192-88, 64 FR 69660, Dec 14, 1999]
Interpretation Summaries	**Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489**.** **Interpretation: PI-ZZ-093 Date: April 20, 1972** This interpretation clarifies that Section 192.485 gives the operator two choices when an area of general corrosion causes reduced wall thickness: (1) Replace the generally corroded segment of pipe; or (2) Reduce the operating pressure commensurate with the strength of the remaining pipe wall thickness.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. Operators must document areas of localized corrosion pitting in terms of replacement or reduction in pressure.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not repair or replace pipe with localized corrosion pitting, or reduce the operating pressure commensurate with the remaining strength of the pipe. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. As-builts, operator repair records, internal inspection survey reports, exposed pipe inspection reports, or pictures.

Other Special Notations	Similar to section 192.485(a), the reporting requirement in section 191.23 (a)(1) Reporting safety-related conditions, with respect to localized corrosion pitting. Operators shall – with noted exceptions – file a SRCR for pipelines (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, where **localized corrosion pitting** (exist) to a degree where leakage might result. Also note: Per SRCR requirements in section 191.25(a) Filing safety-related condition reports, each report of a safety-related condition under section 191.23(a) must be filed (received by the Associate Administrator, OPS) in writing within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.485(c)**
Section Title	**Remedial measures: Transmission lines.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt 192-88, 64 FR 69660, Dec 14, 1999]
Interpretation Summaries	**Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489**.** **Interpretation: PI-ZZ-093 Date: April 20, 1972** This interpretation clarifies that Section 192.485 gives the operator two choices when an area of general corrosion causes reduced wall thickness: (1) Replace the generally corroded segment of pipe; or (2) Reduce the operating pressure commensurate with the strength of the remaining pipe wall thickness.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator should have a procedure for calculating the strength of the pipeline based on actual remaining wall thickness and it may be determined by ASME/ANSI B31G, PR 3-805 (RSTRENG disk), or other approved methods.
Examples of a Probable Violation or Inadequate Procedures	1. The remaining strength of the pipe segment is not computed based on actual remaining wall thickness. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. O&M Manual, ASME/ANSI B31G, RSTRENG disk, as-builts, operator repair records, internal inspection survey reports, exposed pipe inspection reports, or pictures.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.487(a)**
Section Title	**Remedial measures: Distribution lines other than cast iron or ductile iron lines.**
Existing Code Language	**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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt 192-88, 64 FR 69660, Dec 8, 1999]
Interpretation Summaries	**Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489**.**
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. Review all segments of the distribution system with a continued history of internal or external corrosion. The operator should have all the records of its pipeline replacements and its pipeline repairs.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not repair or replace a generally corroded segment of pipe. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator repair records, internal inspection survey report, pipe exposure reports, and pictures.
Other Special Notations	The reporting requirement at section 191.23(a)(1) Reporting safety-related conditions, where operators shall – with noted exceptions – file a SRCR for pipelines (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, where general corrosion has reduced the wall thickness to less than that required for the maximum allowable operating pressure (of its pipeline). Also note: Per SRCR requirements in section 191.25(a) Filing safety-related

	condition reports, each report of a safety-related condition under section 191.23(a) must be filed (received by the Associate Administrator, OPS) in writing within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.487(b)**
Section Title	**Remedial measures: Distribution lines other than cast iron or ductile iron lines.**
Existing Code Language	**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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt 192-88, 64 FR 69660, Dec 8, 1999]
Interpretation Summaries	**Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489**.**
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator should have documentation of areas of localized corrosion pitting in terms of repair or replacement.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not repair or replace a segment of pipe with localized corrosion pitting. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Operator repair records, internal inspection survey report, pipe exposure reports, and pictures.
Other Special Notations	Similar to section 192.487(a), the reporting requirement in section 191.23(a)(1) Reporting safety-related conditions, with respect to localized corrosion pitting. Operators shall – with noted exceptions – file a SRCR for pipelines (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, where **localized corrosion pitting** (exist) to a degree where leakage might result. Also note: Per SRCR requirements in section 191.25(a) Filing safety-related condition reports, each report of a safety-related condition under section 191.23(a)

	must be filed (received by the Associate Administrator, OPS) in writing within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition.

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.489(a)**
Section Title	**Remedial measures: Cast iron and ductile iron pipelines.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	192-4, 36 FR 12297, June 30, 1971
Interpretation Summaries	**Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489**.**
Advisory Bulletin/Alert Notice Summaries	**Alert Notice: ALN-91-02 NTSB Recommendation S P-91-12, 07/90 Allentown, PA: replacement of case-iron piping.** Gas operators are required to implement a program, based on factors such as age, pipe diameter, operating pressure, soil corrosiveness, existing graphitic damage, leak history, burial depth and external loading, to identify and replace in a planned, timely manner case iron piping systems that may threaten public safety. This Alert Notice also reiterates that current pipeline safety regulations at section 192.489 “Remedial measure: Cast iron and ductile iron pipelines” require that cast iron pipe on which general graphitization is found to a degree where a fracture might result, must be replaced. **Alert Notice: ALN-92-02 Cast Iron Pipe (Supplementary Alert Notice).** This Alert Notice reiterates the requirements of section 192.613 Continuing surveillance, and section 192.489 “Remedial measure: Cast iron and ductile iron pipelines” and states that each operator should have a program to identify and replace those case iron piping systems that may threaten public safety.
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	Cast iron pipe, when graphitized, is relatively brittle which allows far more dramatic failure modes such as rapid crack propagation and circumferential breaks. Such failures are potentially much more severe than more ductile failure modes commonly seen in today’s pipe materials. Smaller diameter cast iron pipes have reportedly been more prone to failure.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not repair or replace the section of pipe where a fracture or leakage might result when graphitization is found. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Pipe exposure reports, repair records, pictures.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.489(b)**
Section Title	**Remedial measures: Cast iron and ductile iron pipelines.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	192-4, 36 FR 12297, June 30, 1971
Interpretation Summaries	**Interpretation: PI-81-019 Date: October 27, 1981** This interpretation clarifies that section 192.459 requires operators to visually inspect any portion of its buried pipeline whenever it has knowledge that the buried portion is exposed. The interpretation further clarifies, that in the event an operator were to learn through participation in a "one-call" system that a portion of its buried pipeline is, or will be exposed, the operator's obligation under section 192.459 is to inspect the exposed portion of its pipeline for evidence of external corrosion and take any remedial action that may be required under sections 192.483 through 192.489.
Advisory Bulletin/Alert Notice Summaries	**Alert Notice: ALN-91-02 NTSB Recommendation S P-91-12, 07/90 Allentown, PA: replacement of case-iron piping.** Gas operators are required to implement a program, based on factors such as age, pipe diameter, operating pressure, soil corrosiveness, existing graphitic damage, leak history, burial depth and external loading, to identify and replace in a planned, timely manner case iron piping systems that may threaten public safety. This Alert Notice also reiterates that current pipeline safety regulations at section 192.489 “Remedial measure: Cast iron and ductile iron pipelines” require that cast iron pipe on which general graphitization is found to a degree where a fracture might result, must be replaced. **Alert Notice: ALN-92-02 Cast Iron Pipe (Supplementary Alert Notice).** This Alert Notice reiterates the requirements of section 192.613. Continuing surveillance and section 192.489 “Remedial measure: Cast iron and ductile iron pipelines” and states that each operator should have a program to identify and replace those case iron piping systems that may threaten public safety.
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. If localized graphitization is detected on cast iron or ductile iron pipe, the operator must take appropriate measures to prevent or arrest any leakage.
Examples of a Probable Violation	1. The operator did not repair or replace or seal by internal sealing methods adequate to prevent or arrest any leakage, those pipeline segments where localized graphitization is found to a degree where any leakage might result.

or Inadequate Procedures	*Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Pipe exposure reports, repair records, pictures.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.490**
Section Title	**Direct Assessment**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	192-101, 70 FR 61575, October 25, 2005
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE RP0502-2002 (To be superseded by NACE SP0502-2008 effective October 1, 2010.)
Guidance Information	1. The operator is required to follow the direct assessment methods outlined for integrity management programs when conducting assessments on pipeline segments that are not included in its integrity management program.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not evaluate the effects of a threat in the first column in carrying out the direct assessment according to the standards in the second column. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Operator’s maintenance records
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.491(a)**
Section Title	**Corrosion control records.**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt 192-78, 61 FR 28770, June 6, 1996]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator shall maintain a record/map of all its cathodically protected facilities including cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. The records may be kept in either electronic or hard copy format. These records must be retained as long as the pipelines remain in service.
Examples of a Probable Violation or Inadequate Procedures	1. An operator has not retained records or maps showing location of cathodically protected piping, facilities, and neighboring structures bonded to the cathodic protection system. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. a. Documentation showing facility is cathodically protected. b. Incomplete or missing record or maps of cathodically protected facilities

Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.491(b)**
Section Title	**Corrosion control records.**
Existing Code Language	Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt 192-78, 61 FR 28770, June 6, 1996]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator shall maintain a record/map of all its cathodically protected facilities including cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system.
Examples of a Probable Violation or Inadequate Procedures	1. An operator has not retained records or maps showing location of cathodically protected piping, facilities, and neighboring structures bonded to the cathodic protection system for as long as the pipeline remains in service. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Documentation showing facility is cathodically protected. 2. Incomplete or missing record or maps of cathodically protected facilities.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 192**
Revision Date	**12/7/2015**
Code Section	**§192.491(c)**
Section Title	**Corrosion control records**
Existing Code Language	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.
Origin of Code	NGPLSA 1968
Last Amendment	[Amdt 192-78, 61 FR 28770, June 6, 1996]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	1. The operator also shall maintain a record of each test, survey, and inspection in sufficient detail to demonstrate the adequacy of their corrosion control procedures. Sufficient detail is recognized to mean that the data is error free (See glossary companion document to SP-01-69) for dissertation on errors in measurements), has been interpreted correctly, integrated with other appropriate data under 192.613, and demonstrate that the operator's corrosion control system for atmospheric, internal, and external corrosion is adequate. 2. The operator must maintain a record of each test, survey, and inspection in sufficient detail to demonstrate the adequacy of their corrosion control procedures 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) (pipe-to-soil monitoring surveys) and (e) (3 year unprotected pipe surveys) and 192.475(b)(removed pipe internal corrosion inspections) must be retained for as long as the pipeline remains in service.
Examples of a Probable Violation or Inadequate Procedures	1. An operator has not retained records of each test, survey, or inspection required by subpart I for the specified retention. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. No documentation showing test, survey, or inspection required under subpart I, was made.
Other Special Notations	