Part 195 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 195 Corrosion Enforcement Guidance

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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 195**
Revision Date	**12/7/2015**
Code Section	**§195.551**
Section Title	**What do the regulations in this subpart cover?**
Existing Code Language	This subpart prescribes minimum requirements for protecting steel pipelines against corrosion.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt. 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. Hazardous liquid and carbon dioxide pipelines are almost exclusively made of steel. 2. §195.551characterizes the activities that are covered by the standards in subpart H (i.e., protecting steel pipelines against external, internal, and atmospheric corrosion). Procedures for controlling corrosion are required by §195.402(a) and §195.402(c)(3) including those for the design, installation, operation and maintenance of CP systems. The criteria for cathodic protection are delineated in NACE RP 0169-2002, (to be superseded by NACE SP 0169-2007, effective October 1, 2010) which is incorporated by reference.
Examples of a Probable Violation or Inadequate Procedures	1. The operator is transporting a hazardous liquid by a pipeline made of a material other than steel and has not notified the Administrator of the hazardous liquid to be transported and material used in the construction of the pipeline. (This would be a violation of 195.8, not 195.551.) *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. Hazardous liquids properties, pipe specifications, mill reports, invoices.

Other Special Notations	In the case of a metallic pipeline made from a material other than steel, the operator is required to notify the Administrator a minimum of 90 days prior to transporting the liquid under 195.8.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.553**
Section Title	**What special definitions apply to this subpart?**
Existing Code Language	This section provides definitions of terms such as “active corrosion”, “electrical survey” and pipeline environment” used in subpart H. In addition, it establishes definitions of “buried” and “you.” The definition of “buried” reflects the common corrosion control practice of treating any portion of pipe in contact with the earth as if that portion were buried. The term “you” has the same meaning as “operator.” The terms “direct assessment” and “external corrosion direct assessment” as utilized in the integrity management programs are also defined.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001; Amdt 195-85, 70 FR 61571, Oct. 25, 2005.
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE Standard SP0169-2007
Guidance Information	1. Glossary of Terms
Examples of a Probable Violation or Inadequate Procedures	
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Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.555**
Section Title	**What are the qualifications for supervisors?**
Existing Code Language	You must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under §195.403(c) for which they are responsible for insuring compliance.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE Standard SP0169-2007
Guidance Information	1. These persons shall have knowledge of the physical sciences and principles of engineering and mathematics, acquired by education and related practical experience, and shall be qualified to engage in the practice of corrosion control for external, internal, and atmospheric corrosion. 2. A qualified person may be a registered professional engineer whose professional activities include suitable experience in corrosion or a person recognized as a corrosion specialist or cathodic protection specialist by NACE, or a person with practical experience and training equivalent to the applicable NACE requirements.
Examples of a Probable Violation or Inadequate Procedures	1. The operator cannot provide documentation that its supervisors have thorough knowledge and/or experience appropriate for their responsibilities. *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 descriptions, documentation of training and experience.

Other Special Notations	Operators may have a hierarchy of personnel responsible for ensuring adequate corrosion control practices are applied to the company's pipelines. Different (operator) supervisors may be responsible for various aspects of the operator's corrosion control program. The supervisor(s) discussed in this regulation are the responsible person(s) who review actual field data for compliance and make decisions concerning remedial action. If the operator does not have qualified personnel, it may utilize the services of a competent, qualified contractor or consultant.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.557(a)**
Section Title	**Which pipelines must have coating for external corrosion control?**
Existing Code Language	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is: Constructed, relocated, replaced, or otherwise changed after the applicable date in §195.401(c), not including the movement of pipe covered by §195.424.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE Standard SP0169-2007
Guidance Information	1. The operator must document the date its pipeline was constructed, relocated, replaced, or otherwise changed.
Examples of a Probable Violation or Inadequate Procedures	1. The operator has a pipeline that does not have an external coating and was constructed, relocated, replaced, or otherwise changed after the applicable dates of installation in section 195.401(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. Construction/repair records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.557(b)**
Section Title	**Which pipelines must have coating for external corrosion control?**
Existing Code Language	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is: Converted under §195.5 and; (1) Has an external coating that substantially meets §195.559 before the pipeline is placed in service; or (2) Is a segment that is relocated, replaced, or substantially altered.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE Standard SP0169-2007
Guidance Information	1. The operator should maintain pipeline design documents to demonstrate that an external coating is specified; and construction documents to demonstrate that the coating was applied, and pipe dig/exposure reports to document that it is evaluating the condition of the external coating on its pipeline whenever its buried pipeline is exposed.
Examples of a Probable Violation or Inadequate Procedures	1. The operator has not evaluated the existing coating of a converted pipeline to determine whether it substantially meets the requirements of §195.559. 2. The operator has not coated a pipeline segment that is relocated, replaced, or substantially altered. *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/repair records

Other Special Notations	Section 195.5 allows up to 12 months for the operator to comply with the subpart H requirements for a converted pipeline.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.559(a)**
Section Title	**What coating material may I use for external corrosion control?**
Existing Code Language	Coating material for external corrosion control under §195.557 must: Be designed to mitigate corrosion of the buried or submerged pipeline.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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. The operator's manual should address procedures on the use and application of coatings such as: Hot-applied bituminous tapes, Petrolatum tapes, Wax tapes, etc. If applicable, the operator's manual should also address procedures on the use and application of coatings used for weighting in submerged services or for insertion in bored/drilled crossings such as Concrete coatings and Abrasive Resistant over coating. 3. Some of the common types of pipeline coatings utilized in the industry include: Fusion Bonded Epoxy, Coal Tar Enamel, Tape coatings, etc.; such coatings are widely used throughout the pipeline industry and likely to be found in operators' manuals.

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 possess the required corrosion mitigating 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. Coating specifications, O&M Manual
Other Special Notations	Coating specifications and procedures are usually reviewed during construction inspections or after an incident where failed coating is suspected.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.559(b)**
Section Title	**What coating material may I use for external corrosion control?**
Existing Code Language	Coating material for external corrosion control under §195.557 must: Have sufficient adhesion to the metal surface to prevent under film migration of moisture.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007; NACE Standard RP0394-2002; NACE Standard RP0402-2002; NACE Standard RP0375-99; NACE Standard RP0105-2005; NACE Standard RP0303-2003; NACE Standard RP0602-2002; NAPCA BULLETIN 16-94; 3M™ Scotchkote™ Fusion-Bonded Epoxy Coating 6233 Data Sheet; and 3M™ Scotchkote™ Fusion-Bonded Epoxy Coating 6233/206N/226N/226N+Field Joint Application Guide.
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 possess the required adhesive 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. Coating specifications, O&M Manual, Review of any incident where insufficient adhesion of the coating may have been a contributing factor. Pictures of areas of disbonded coating on relatively newly coated or recoated pipe.
Other Special Notations	Proper surface preparation is critical for ensuring sufficient adhesion. The operator should follow the manufacturer's recommendations and applicable industry standards to ensure adequate surface preparation. In additions to the Other Ref. Material & Sources noted above, the following are examples of additional source material for reference (including specific coating products, specific data sheet/ application and inspection specifications, and performance criteria): a. NAPCA BULLETIN 16-94 NAPCA RECOMMENDED PRACTICE FOR SURFACE CONDITION OF PIPE AS RECEIVED AT THE COATING PLANT b. NAPCA Bulletin 17-98 FBE Anomalies Trouble-Shooting Guide c. NAPCA Bulletin 6-69-94-2 SUGGESTED PROCEDURES FOR COATING OF GIRTH WELDS WITH FUSION BONDED EPOXY d. 3M™ Scotchkote™ Fusion-Bonded Epoxy Coating 6233/206N/226N/226N+ Field Joint Application Guide

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.559(c)**
Section Title	**What coating material may I use for external corrosion control?**
Existing Code Language	Coating material for external corrosion control under §195.557 must: Be sufficiently ductile to resist cracking.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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. Examples of specific coating products in use by pipeline operators include: a. 3M™ Scotchkote™ Liquid Epoxy Coating 323P Data Sheet and Application Instructions b. 3M™ Scotchkote™ Fusion-Bonded Epoxy Coating 6233 Data Sheet
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 possess the required cracking resistance. *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. Coating specifications, O&M Manual, Review of any incident where cracking of the coating may have been a contributing factor.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.559(d)**
Section Title	**What coating material may I use for external corrosion control?**
Existing Code Language	Coating material for external corrosion control under §195.557 must: Have enough strength to resist damage due to handling and soil stress.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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. Examples of specific coating products in use by pipeline operators include: a. 3M™ Scotchkote™ Liquid Epoxy Coating 323P Data Sheet and Application Instructions b. 3M™ Scotchkote™ Fusion-Bonded Epoxy Coating 6233 Data Sheet
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 possess the required strength 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. Coating specifications, O&M Manual
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.559(e)**
Section Title	**What coating material may I use for external corrosion control?**
Existing Code Language	Coating material for external corrosion control under §195.557 must: Support any supplemental cathodic protection.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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. Examples of specific coating products in use by pipeline operators include: a. 3M™ Scotchkote™ Liquid Epoxy Coating 323P Data Sheet and Application Instructions b. 3M™ Scotchkote™ Fusion-Bonded Epoxy Coating 6233 Data Sheet
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 support supplemental 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. Coating specifications, O&M Manual
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.559(f)**
Section Title	**What coating material may I use for external corrosion control?**
Existing Code Language	Coating material fo r external corrosion control under §195.557 must: If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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. Examples of specific coating products in use by pipeline operators include: a. 3M™ Scotchkote™ Liquid Epoxy Coating 323P Data Sheet and Application Instructions b. 3M™ Scotchkote™ Fusion-Bonded Epoxy Coating 6233 Data Sheet
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. Coating specifications, O&M Manual
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.561(a)**
Section Title	**When must I inspect pipe coating used for external corrosion control?**
Existing Code Language	You must inspect all external pipe coating required by § 195.557 just prior to lowering the pipe into the ditch or submerging the pipe.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007

Guidance Information	1. Electrical testing is commonly known as "jeeping." 2. The voltage utilized for the electrical testing should 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. 3. Some examples of appropriate jeep settings for pipeline coatings can be found in the following NACE Standards: a. <u>NACE SP0490-2007 Standard Practice Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coatings of 250 to 760 µm (10 to 30 mil)</u> b. <u>NACE Standard RP0274-2004 Standard Recommended Practice High-Voltage Electrical Inspection of Pipeline Coatings</u> 4. 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 into the ditch or submerging 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. O&M Manual, Maintenance records, Manufacturer's maintenance recommendations, photographs, construction records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.561(b)**
Section Title	**When must I inspect pipe coating used for external corrosion control?**
Existing Code Language	You must repair any coating damage discovered.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007

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. 2. 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 is 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. 3. Coating material damaged or improperly installed must be repaired.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not properly 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, photographs.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.563(a)**
Section Title	**Which pipeline must have cathodic protection?**
Existing Code Language	Each buried or submerged pipeline that is constructed, relocated, replaced, or otherwise changed after the applicable date in §195.401(c) must have cathodic protection. The cathodic protection must be in operation not later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. The operator must install its pipeline in accordance with § 195.401(c). Any pipeline installed after the applicable dates must have cathodic protection applied and in operation within 1 year after the pipeline was constructed, relocated, replaced, or otherwise changed "In operation" means that a survey has been conducted and that the applied cathodic protection meets the criteria of § 195.571.
Examples of a Probable Violation or Inadequate	1. The operator has a pipeline segment that is new, replaced, or relocated after the applicable date in §195.401(c) and cathodic protection was not installed and in operation within 1 year. *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. Should gather construction as-builts with specific in the ditch dates. Should look for work orders or other documents to see when protection was applied. 2. There may not be "CP" surveys per se so you should be sure to conduct interviews of appropriate staff to get an operator statement.

Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.563(b)**
Section Title	**Which pipeline must have cathodic protection?**
Existing Code Language	Each buried or submerged pipeline converted under §195.5 must have cathodic protection if the pipeline: 1. Has cathodic protection that substantially meets § 195.571 before the pipeline is placed in service; or 2. Is a segment that is relocated, replaced, or substantially altered.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. If an operator has converted a pipeline to service under §195.563(b), there are two alternatives for the operator to consider: a. If the pipeline originally had cathodic protection applied that substantially meets the requirements of 195.571 before the conversion, the operator must maintain the cathodic protection. b. If the pipeline is a segment that has been relocated, replaced, or substantially altered, it must have cathodic protection applied that meets the requirements of 195.571.

Examples of a Probable Violation or Inadequate Procedures	1. The operator did not maintain the cathodic protection previously applied to the converted pipeline. 2. A pipeline segment has been relocated, replaced, or substantially altered, and the operator has not applied 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	
Other Special Notations	Section 195.5 allows up to 12 months to comply with the subpart H requirements for converted pipe.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.563(c)**
Section Title	**Which pipeline must have cathodic protection?**
Existing Code Language	All other buried or submerged pipelines that have an effective external coating must have cathodic protection. Except as provided by paragraph (d) of this section, this requirement does not apply to breakout tanks and does not apply to buried piping in breakout tank areas and pumping stations until December 29, 2003.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. All pipelines not identified in §195.563(a) or (b) above that are buried or submerged that have an effective external coating, must have cathodic protection. A coating is not considered "effective" if the current required to cathodically protect the pipeline is substantially the same as if the pipe were bare. (For additional information on determining effectiveness of coating, see guidance for §192.457(a) in the Part 195 Corrosion Control Enforcement Guidance). **This is a deliberate reference to 192.** 2. This section did not apply to breakout tanks or buried piping in breakout tank areas and pumping stations until December 29, 2003.
Examples of a Probable Violation or Inadequate Procedures	1. The operator has a buried or submerged pipeline not identified in §195.563(a) or (b) with an effective external coating that does not have 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	

Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.563(d)**
Section Title	**Which pipeline must have cathodic protection?**
Existing Code Language	Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where regulations in effect before January 28, 2002 required cathodic protection as a result of electrical inspections. See previous editions of this part in 49 CFR, parts 186 to 199.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. The previous edition of §195.414(c) required operators to electrically inspect breakout tank areas and pump station piping and apply cathodic protection as needed. Also, the previous edition of §195.416(d) required operators to electrically inspect all bare pipelines not cathodically protected at intervals not exceeding 5 years and apply cathodic protection as applicable. 2. Operators would only apply cathodic protection to areas where needed. For pipelines in any of these three areas, the cathodic protection previously applied must be maintained.
Examples of a Probable Violation or Inadequate Procedures	1. The operator has bare pipelines or piping in breakout tank areas or pump stations where the cathodic protection was previously applied as a result of electrical surveys, but has not been maintained. *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. Maintenance and cathodic protection records.

Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.563(e)**
Section Title	**Which pipeline must have cathodic protection?**
Existing Code Language	Unprotected pipe must have cathodic protection if required by § 195.573(b).
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. Operators must perform electrical surveys on their unprotected pipe per the requirements of 195.573(b) and apply cathodic protection as required. 2. An electrical survey on unprotected pipe typically involves identifying locations where current is leaving the pipe, usually using a technique called a side drain survey or two cell survey to look for changes in current direction (reversals). When a current drain is identified and quantified then an anode (cathodic protection) can be applied at that location.
Examples of a Probable Violation or Inadequate Procedures	1. The operator has not performed electrical surveys on its unprotected pipe per the requirements of 195.573(b) or applied cathodic protection if active corrosion was 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	
Other Special Notations	All effectively coated pipelines are required to have cathodic protection.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.565**
Section Title	**How do I install cathodic protection on breakout tanks?**
Existing Code Language	After October 2, 2000, when you (operator) install cathodic protection under §195.563(a) to protect the bottom of an aboveground breakout tank of more than 500 barrels capacity built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the system in accordance with API Recommended Practice 651. However, installation of the system need not comply with API Recommended Practice 651 on any tank for which you note in the corrosion control procedures established under §195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of the tank.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. The operator must develop procedures for corrosion control in accordance with §195.402(c)(3). Whenever the operator installs cathodic protection on an aboveground breakout tank, the installation must be in accordance with API Recommended Practice 651 unless the operator documents and justifies why compliance with all or certain provisions of the standard are not necessary.
Examples of a Probable Violation or Inadequate Procedures	1. The operator has not installed cathodic protection on required tanks in accordance with API Recommended Practice 651 within the specified time period and has not justified why all or certain provisions of the Recommended Practice are not necessary for the safety of the tank. *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, API Recommended Practice 651, API Standard 653

Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.567(a)**
Section Title	**Which pipelines must have test leads and what must I do to install and maintain the leads?**
Existing Code Language	***General:*** Except for offshore pipelines, each buried or submerged pipeline or segment of pipeline under cathodic protection required by this subpart must have electrical test leads for external corrosion control. However, this requirement does not apply until December 27, 2004 to pipelines or pipeline segments on which test leads were not required by regulations in effect before January 28, 2002.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	**Interpretation: PI- 09-0014 Date: August 18, 2009** Clarifies that pipeline operators are obligated to install and maintain test leads at intervals frequent enough to obtain measurements indicating the adequacy of cathodic protection. To the extent readings sufficient to indicate the adequacy of cathodic protection at a particular location can be obtained from exposed pipe and appurtenances, it is unnecessary to install test leads at that point. Therefore, taking readings directly from exposed pipe that is physically accessible is not a violation of §195.567(a). However, collecting cathodic protection readings directly from the pipe has the potential to compromise the protective coatings on the pipe, subjecting that exposed pipe to atmospheric corrosion. It is also important to recognize that test leads may be necessary for certain portions of buried pipeline facilities, even though they are in close proximity to exposed pipe.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	<u>1. Offshore pipelines are not covered by the test lead requirements and may only have test points at risers or platforms.</u>
Examples of a Probable Violation or Inadequate Procedures	1. An operator has not installed test leads as required. (Most test lead issues would be cited under §195.567(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	
Other Special Notations	The operator should indicate the test leads used to show adequacy of cathodic protection.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.567(b)**
Section Title	**Which pipelines must have test leads and what must I do to install and maintain the leads?**
Existing Code Language	***Installation:*** You must install test leads as follows: 1. Locate the leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection. 2. Provide enough looping or slack so backfilling will not unduly stress or break the lead and the lead will otherwise remain mechanically secure and electrically conductive. 3. Prevent lead attachments from causing stress concentrations on pipe. 4. For leads installed in conduits, suitably insulate the lead from the conduit. 5. At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007; ANSI/ASME B31.4-2002
Guidance Information	1. The operator must have sufficient test leads where data is collected to demonstrate that their entire pipeline is cathodically protected. Test leads are usually copper wires that are attached to the pipeline and brought into a test station to provide an electrical connection to the pipeline. Measurements should be taken at these test stations while conducting the annual survey. Operators may install additional wires on their pipe to perform special tests on the cathodic protection system. Potentials at these locations are not required during annual cathodic protection surveys.

	2. 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 right-of-way of a buried pipeline. 3. Has the operator performed a close-interval-survey (CIS) on the pipeline? 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. After performing a CIS, the operator may have found areas of low pipe-to-soil potentials between the test stations which indicate a need to take remedial action. 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. 6. Some factors to consider: a. Pipe coating - (coating quality surveys, e.g. CIS, DCVG or ACVG) b. Age of pipe - (pipe coating may deteriorate with age) Increasing current requirements over time, increasing current output from rectifiers over time. c. River crossings - current measuring test stations on either side of the crossing. A comparison of the magnitude of current pick up from each side of the river will allow one to calculate current pick up in the river. d. A review should be made of the operator's standards for making test lead connections to ensure proper application and continuity. 1. INSTALLATION METHODS Some acceptable methods include the following: 1.1 <u>Thermite welding.</u> (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 <u>Solder connections</u>. 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 <u>Mechanical connections</u>. 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.
Examples of a Probable Violation or Inadequate Procedures	1. 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. 2. The thermite welding charge is greater than the manufacturers recommended cartridge size. 3. 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	
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.567(c)**
Section Title	**Which pipelines must have test leads and what must I do to install and maintain the leads?**
Existing Code Language	***Maintenance:*** You must maintain the test lead wires in a condition that enables you to obtain electrical measurements to determine whether cathodic protection complies with §195.571.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP 0169-2007
Guidance Information	1. When the operator discovers that a required test lead is damaged or defective to the point that the ability to perform electrical measurements is impaired, the operator must take action to repair or replace the test lead. Remediation must be completed prior to the next monitoring cycle.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not maintain the test lead wires so that electrical measurements could be obtained to determine whether cathodic protection is adequate. 2. The operator did not repair or replace defective test leads when found so that electrical measurements could be obtained to determine whether cathodic protection is adequate. *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 195**
Revision Date	**12/7/2015**
Code Section	**§195.569**
Section Title	**Do I have to examine exposed portions of buried pipelines?**
Existing Code Language	Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion, if the pipe is bare or if the coating is deteriorated. If you find external corrosion requiring corrective action under § 195.585, you must 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	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP 0169-2007
Guidance Information	1. The operator should have this procedure demonstrated in its O&M manual, or be able to produce evidence of compliance, and demonstrate that its procedure is carried out. 2. 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 Procedures	1. The operator's pipe was exposed but was not examined for evidence of external corrosion. 2. If external corrosion requiring remedial action under section 195.585 was found, and the operator did not 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. *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 195**
Revision Date	**12/7/2015**
Code Section	**§195.571**
Section Title	**What criteria must I use to determine the adequacy of cathodic protection?**
Existing Code Language	Cathodic protection required by this Subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE SP 0169 (incorporated by reference, see § 195.3).
Origin of Code	HLPLSA 1979
Last Amendment	Amdt. 195-94, PHMSA-2008-0301-0025, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	Section 6: Criteria and Other Considerations for Cathodic Protection See Also: Bibliography for Section 6 6.1 Introduction 6.1.1 This section lists criteria and other considerations for cathodic protection that will indicate, when used either separately or in combination, whether adequate cathodic protection of a metallic piping system has been achieved (see also Section 1, Paragraphs 1.2 and 1.4). 6.1.2 The effectiveness of cathodic protection or other external corrosion control measures can be confirmed by visual observation, by measurements of pipe wall thickness, or by use of internal inspection devices. Because such methods sometimes are not practical, meeting any criterion or combination of criteria in this section is evidence that adequate cathodic protection has been achieved. When excavations are made for any purpose, the pipe should be inspected for evidence of corrosion and/or coating condition. 6.1.3 The criteria in this section have been developed through laboratory experiments and/or verified by evaluating data obtained from successfully operated cathodic protection systems. Situations in which a single criterion for evaluating the effectiveness of cathodic protection may not be satisfactory for all conditions may exist. Often a combination of criteria is needed for a single structure. 6.1.4 Sound engineering practices shall be used to determine the methods and frequency of testing required to satisfy these criteria.

6.1.5 Corrosion leak history is valuable in assessing the effectiveness of cathodic protection. Corrosion leak history by itself, however, shall not be used to determine whether adequate levels of cathodic protection have been achieved unless it is impractical to make electrical surveys.

6.2 Criteria

6.2.1 It is not intended that persons responsible for external corrosion control be limited to the criteria listed below. Criteria that have been successfully applied on existing piping systems can continue to be used on those piping systems. Any other criteria used must achieve corrosion control comparable to that attained with the criteria herein.

6.2.2 Steel and Cast Iron Piping

6.2.2.1 External corrosion control can be achieved at various levels of cathodic polarization depending on the environmental conditions. However, in the absence of specific data that demonstrate that adequate cathodic protection has been achieved, one or more of the following shall apply:

6.2.2.1.1 A negative (cathodic) potential of at least 850 mV with the cathodic protection applied. This potential is measured with respect to a saturated copper/copper sulfate reference electrode contacting the electrolyte. Voltage drops other than those across the structure-to-electrolyte boundary must be considered for valid interpretation of this voltage measurement.

NOTE: Consideration is understood to mean the application of sound engineering practice in determining the significance of voltage drops by methods such as:

6.2.2.1.1.1 Measuring or calculating the voltage drop(s);

6.2.2.1.1.2 Reviewing the historical performance of the cathodic protection system;

6.2.2.1.1.3 Evaluating the physical and electrical characteristics of the pipe and its environment; and

6.2.2.1.1.4 Determining whether or not there is physical evidence of corrosion.

6.2.2.1.2 A negative polarized potential (see definition in Section 2) of at least 850 mV relative to a saturated copper/copper sulfate reference electrode.

6.2.2.1.3 A minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of polarization can be measured to satisfy this criterion.

6.2.2.2 Special Conditions

6.2.2.2.1 On bare or ineffectively coated pipelines where long-line corrosion activity is of primary concern, the measurement of a net protective current at predetermined current discharge points from the electrolyte to the pipe surface, as measured by an earth current technique, may be sufficient.

6.2.2.2.2 In some situations, such as the presence of sulfides, bacteria, elevated temperatures, acid environments, and dissimilar metals, the criteria in Paragraph 6.2.2.1 may not be sufficient.

6.2.2.2.3 When a pipeline is encased in concrete or buried in dry or aerated high-resistivity soil, values less negative than the criteria listed in Paragraph 6.2.2.1 may be sufficient.

6.2.2.3 PRECAUTIONARY NOTES

6.2.2.3.1 The earth current technique is often meaningless in multiple pipe rights-of-way, in high-resistivity surface soil, for deeply buried pipe, in stray-current areas, or where local corrosion cell action predominates.

6.2.2.3.2 Caution is advised against using polarized potentials less negative than -850 mV for cathodic protection of pipelines when operating pressures and conditions are conducive to stress corrosion cracking (see references on stress corrosion cracking in the Bibliography for Section 6).

6.2.2.3.3 The use of excessive polarized potentials on externally coated pipelines should be avoided to minimize cathodic disbondment of the coating.

6.2.2.3.4 Polarized potentials that result in excessive generation of hydrogen should be avoided on all metals, particularly higher strength steel, and certain grades of stainless steel, titanium, aluminum alloys, and prestressed concrete pipe.

6.2.3 Aluminum Piping

6.2.3.1 The following criterion shall apply: a minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of this polarization can be used in this criterion.

6.2.3.2 PRECAUTIONARY NOTES

6.2.3.2.1 Excessive Voltages: Notwithstanding the minimum criterion in Section 6.2.3.1, if aluminum is cathodically protected at voltages more negative than -1200 mV measured between the pipe surface and a saturated copper/copper sulfate reference electrode contacting the electrolyte and compensation is made for the voltage drops other than those across the pipe-electrolyte boundary, it may suffer corrosion as the result of the buildup of alkali on the metal surface. A polarized potential more negative than -1,200 mV should not be used unless previous test results indicate that no appreciable corrosion will occur in the particular environment.

6.2.3.2.2 Alkaline Conditions: Aluminum may suffer from corrosion under high-pH conditions and application of cathodic protection tends to increase the pH at the metal surface. Therefore, careful investigation or testing should be made before applying cathodic protection to stop pitting attack on aluminum in environments with a natural pH in excess of 8.0.

6.2.4 Copper Piping

6.2.4.1 The following criterion shall apply: a minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of this polarization can be used in this criterion.

6.2.5 Dissimilar Metal Piping

6.2.5.1 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.

6.2.5.2 PRECAUTIONARY NOTE

6.2.5.2.1 Amphoteric materials that could be damaged by high alkalinity created by

	cathodic protection should be electrically isolated and separately protected. 6.3 Other Considerations 6.3.1 Methods for determining voltage drop(s) shall be selected and applied using sound engineering practices. Once determined, the voltage drop(s) may be used for correcting future measurements at the same location, providing conditions such as pipe and cathodic protection system operating conditions, soil characteristics, and external coating quality remain similar. (Note: Placing the reference electrode next to the pipe surface may not be at the pipe-electrolyte interface. A reference electrode placed at an externally coated pipe surface may not significantly reduce soil voltage drop in the measurement if the nearest coating holiday is remote from the reference electrode location.) 6.3.2 When it is impractical or considered unnecessary to disconnect all current sources to correct for voltage drop(s) in the structure-to-electrolyte potential measurements, sound engineering practices should be used to ensure that adequate cathodic protection has been achieved. 6.3.3 Where feasible and practicable, in-line inspection of pipelines may be helpful in determining the presence or absence of pitting corrosion damage. Absence of external corrosion damage or the halting of its growth may indicate adequate external corrosion control. The in-line inspection technique, however, may not be capable of detecting all types of external corrosion damage, has limitations in its accuracy, and may report as anomalies items that are not external corrosion. For example, longitudinal seam corrosion and general corrosion may not be readily detected by in-line inspection. Also, possible thickness variations, dents, gouges, and external ferrous objects may be detected as corrosion. The appropriate use of in-line inspection must be carefully considered. 6.3.4 Situations involving stray currents and stray electrical gradients that require special analysis may exist. For additional information, see Section 9, "Control of Interference Currents". ***Exxon Mobil Pipeline Company [5-2003-5006]* (July 1, 2004)** – Operators using the -850mV cathodic potential criterion must account for voltage drop using sound engineering methods. The universally accepted method is the "instant off" technique. When this is impractical, the use of extrapolation methods to determine the polarized potential of pipe structures and computerized survey techniques is an acceptable method. The alleged violation in this case was withdrawn. ***Marathon Ashland Pipe Line, LLC [5-2003-5013]* (February 16, 2006)** – An IR free (IRF) reading, taken with the rectifier operating uninterrupted, is not an acceptable method for determining voltage drop. In addition, the operator's documentation must indicate the criterion that was used to consider voltage drop. CO ***Sunoco Pipeline, L.P. [4-2007-5040]* (December 16, 2010)** – To consider IR drop using the "instant off" technique, "instant off" potentials must be recently tested, and must be used to evaluate the CP survey readings. CO ***Alyeska Pipeline Service Company [5-2004-5015]* (September 24, 2007)** – Found that paragraph 6.3 of the NACE standard does not allow the operator to use ILI instead of satisfying the criteria in NACE 6.2. The operator must still comply with one or more of the applicable criteria. CO

Examples of a Probable Violation or Inadequate Procedures	1. Operator did not utilize one of the criteria listed in NACE SP0169-2007. *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. Records of annual cathodic protection readings, O&M Manual, operator personnel statements, maintenance records, operator's procedural requirements.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.573(a)**
Section Title	**What must I do to monitor external corrosion control?**
Existing Code Language	Protected pipelines: You must do the following to determine whether cathodic protection required by this subpart complies with § 195.571: (1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months. 2) Identify not more than 2 years after cathodic protection is installed, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE SP 0169 (incorporated by reference, see § 195.3).
Origin of Code	HLPLSA 1979
Last Amendment	Amdt. 195-94, PHMSA-2008-0301-0025, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP 0169-2007
Guidance Information	1. Section 195.573(a)(1) - This requirement is usually referred to as the "annual CP survey". Operators who are electrically monitoring their entire bare (ineffectively coated) sections of pipeline on a 3 year basis would not have to include their hot spot protected sections of pipe in their annual CP survey. 2. Section 195.573(a)(2) – The operator must identify not more than 2 years after cathodic protection is installed, the circumstances in which a close interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard SP0169-2007. If the operator has determined that a close interval survey was necessary, the operator should have records to show compliance with this section. 3. Section 10.1.1.3 states, "Where practicable and determined necessary by sound engineering practice, a detailed (close-interval) potential survey should be conducted to (a) assess the effectiveness of the cathodic protection system; (b) provide base line operating data; (c) locate areas of inadequate protection levels; (d) identify

	locations likely to be adversely affected by construction, stray currents, or other unusual environmental conditions; or (e) select areas to be monitored periodically." 4. ***Alyeska Pipeline Service Company [5-2005-5023]* (July 28, 2009)** – Found that operator failed to test whether road casings were electrically isolated from the pipeline. Operator argued that § 195.575 governs electrical isolation of road casings and that it does not specify an interval for testing, but § 195.575 is meant to ensure that electrical isolation is adequate when it is installed. All post-installation inspections and tests of cathodic protection facilities are covered by § 195.573. Unless road casings are tested annually, the operator cannot get an accurate picture of the effectiveness of cathodic protection on the pipe inside the casing. CO, CP 5. ***Navajo Nation Oil & Gas Company, Inc. [4-2006-5029]* (March 17, 2010)** – Operators are required to test for cathodic protection each calendar year at intervals not exceeding 15 months according to **§195.573(a)**. Note that if an operator discovers a deficiency in corrosion control, **§ 195.573(e)** is the regulation that requires them to correct it. This case was actually a bad example of § 195.573(a). 6. ***Kinder Morgan Energy Partners, L.P. [4-2006-5023]* (August 31, 2010)** – Operator failed to properly take IR drop into account. On one pipeline, the operator was taking IR drop readings from certain locations and extrapolating them to other locations along the pipeline; this does not account for potential environmental and soil changes at different locations and does not satisfy the NACE standard. On another pipeline, the operator claimed that it combined methods of "consideration" of IR drop, but failed to demonstrate how these methods were used. Historical performance of the CP system does not demonstrate compliance with the regulation. CO, CP
Examples of a Probable Violation or Inadequate Procedures	1. A cathodically protected pipeline has not been tested at least once each calendar year at intervals not to exceed 15 months to determine whether the requirements of §195.571 have been met. 2. Testing of separately protected short sections of pipeline or bare ineffectively coated pipelines have not been conducted at least once each calendar year at intervals not to exceed 15 months. Or, if tests at those intervals are impractical, testing at least once every 3 calendar years, but with intervals not exceeding 39 months. 3. The operator has not identified, within the required time frame, the circumstances in which a close interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard SP0169-2007. 4. The operator does not have records to show 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. Annual survey documentation, close interval survey documentation, surveys of separately protected short sections or bare ineffectively coated pipelines.

Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.573(b)**
Section Title	**What must I do to monitor external corrosion control?**
Existing Code Language	Unprotected pipe: You must reevaluate your unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found, as follows: (1)Determine the areas of active corrosion by electrical survey, or where an electrical survey is impractical, 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. (2) For the period in the first column, the second column prescribes the frequency of evaluation. Period: Evaluation Frequency Before December 29, 2003: At least every 5 calendar years, but with intervals not exceeding 63 months beginning December 29, 2003: At least once every 3 calendar years, but with intervals not exceeding 39 months.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP 0169-2007
Guidance Information	1. 195.573(b) This section requires the operator to conduct an electrical survey or, if the operator declares an electrical survey to be impractical, review other applicable records to determine areas of “active corrosion.” The operator must demonstrate why it is "impractical.” The operator need not prove physical impossibility. If such areas are discovered, the operator must cathodically protect them in accordance with subpart H. 2. One method to identify areas of “active corrosion” on a bare or poorly coated pipeline is to perform a cell-to-cell survey (also called a “side-drain survey”). This electrical survey will identify current discharge points which indicate anodic areas where corrosion is occurring.

	3. Galvanic anodes are installed at these points on the pipeline and tests should be made to ensure that the problem has been remediated. This is known as “net protective current” as discussed in the NACE Standard SP0169-2007 under “Special Conditions, section 6.2.2.2.1. The inspector is cautioned that this survey may not work in all areas. Refer to “Precautionary Notes” section 6.2.2.3.1 in NACE Standard SP 0169-2007. 4. Operators who do not run electrical surveys over their unprotected metallic pipelines must have developed a separate program (documented) to effectively monitor unprotected coated and bare (ineffectively coated) pipelines. The operators must demonstrate that they are effectively using their review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records and the pipeline environment. Based on the results of this monitoring, operators must take action to cathodically protect areas of active corrosion on their system. 5. Unless an operator is attempting to cathodically protect a bare pipeline in its entirety, the operator is not required to monitor anodes installed to mitigate an area of active corrosion on an annual basis as defined in the regulation.
Examples of a Probable Violation or Inadequate Procedures	1. A non-cathodically protected pipeline initially evaluated pursuant to § 195.573, is not re-evaluated at least every 3 years not to exceed 39 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	
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.573(c)**
Section Title	**What must I do to monitor external corrosion control?**
Existing Code Language	
Origin of Code	HLPLSA 1979
Last Amendment	Amdt. 195-73A, 67 FR 70118, Nov. 20, 2002
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. **For rectifiers**: Current output should be sufficient to protect the pipeline. 2. There is the possibility that the rectifier case may be shorted to the AC side of the rectifier and that someone touching it could become the ground for the system and receiving a severe (possibly fatal) shock. 3. Other impressed current power sources include propane or natural gas driven thermocouples, photovoltaic (Solar) power sources must include sufficient battery power to maintain adequate CP overnight. 4. Acceptable remote monitoring devices (lights, whirlybirds, spinners) must be driven by the DC side of the rectifier and must be designed to shut off if the required level of protection for that segment of line falls below the criteria for required current output. 5. Remote monitoring devices which are used to read rectifiers, bonds, or test stations, must be periodically calibrated or checked for accuracy if the readings are used to meet compliance requirements and time frames. 6. The operator must maintain reverse current switch, diode and interference bond records for appropriate time frames. There are 2 types of interference bonds the operator must consider. The first type is one that if broken, the operator's pipeline is not in jeopardy which is known as a "non-critical" bond. This bond must be monitored once per year not to exceed 15 months. The second type is one that if broken, the operator's pipeline is in jeopardy which is known as a "critical" bond. This bond must be monitored 6 times per year not to exceed 2 ½ months. Bonds across insulators utilized by an operator to facilitate CP (continuity bonds) are not required to be tested as interference bonds.

Examples of a Probable Violation or Inadequate Procedures	1. The operator did not inspect its rectifiers; reverse current switches, diodes and critical interference bonds six times each calendar year, with intervals not exceeding 2 1/2 months. The operator did not inspect its non-critical interference bonds at least once each calendar year, with 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. O & M procedure, maintenance records, survey records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.573(d)**
Section Title	**What must I do to monitor external corrosion control?**
Existing Code Language	Breakout tanks: You must inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. However, this inspection is not required if you note in the corrosion control procedures established under § 195.402(c)(3) why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP 0169-2007; API Recommended Practice 651
Guidance Information	1. The operator is required to maintain procedures and records that address cathodic protection of its aboveground breakout tanks. API Recommended Practice 651 is commonly utilized by industry. The operator must develop procedures for corrosion control in accordance with §195.402(c)(3). Whenever the operator inspects its cathodic protection systems on an aboveground breakout tank, the inspection must be in accordance with API Recommended Practice 651, unless the operator documents and justifies why compliance with all or certain operation and maintenance provisions of the standard are not necessary.
Examples of a Probable Violation or Inadequate	1. The operator did not inspect the cathodic protection system on the bottom of an aboveground breakout tank, to ensure the operation and maintenance of the system was in accordance with API Recommended Practice 651. 2. The operator did not document and justify why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 was not 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 procedure, maintenance records, API Recommended Practice 651.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.573(e)**
Section Title	**What must I do to monitor external corrosion control?**
Existing Code Language	Corrective action: You must correct any deficiency in corrosion control identified by monitoring as soon as required by §195.401(b). However, if the deficiency involves a pipeline in an integrity management program under §195.452, you must correct the deficiency as required by §195.452(h).
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP 0169-2007
Guidance Information	1. The operator is required to maintain records and its procedures should address how prompt remedial action is defined and addressed. 2. ***Navajo Nation Oil & Gas Company, Inc. [4-2006-5029]*** **(March 17, 2010)** – Found that the operator failed to correct an identified deficiency in corrosion control within a reasonable time as required. The operator had a rectifier that was not operating for a period of 20 months; the fact that another rectifier 3 miles away was operating and that pipe-to-soil readings were adequate during this time does not mitigate this deficiency. The rectifier still needed to be fixed within a reasonable time. CP 3. ***Colonial Pipeline Company [2-2008-5005]*** **(July 12, 2010)** – Found that the operator failed to correct an identified deficiency in corrosion control within a reasonable time as required. Difficult site conditions, permit requirements, or a lack of electrical power are not a valid defense to this requirement. CP

Examples of a Probable Violation or Inadequate Procedures	1. Prompt remedial action is not taken to correct a deficiency indicated by monitoring. Inspection guidelines for §195.573 (e). 2. The definition of “prompt” will vary with the circumstances. Enforcement should be sought only when the investigator is convinced that corrective action was unreasonably delayed. 3. The operator should be required to have procedures (per 195.573 (e) for responding to deficiencies found by the required monitoring. 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. 4. These time frames should give consideration to the population density and environmental concerns of the area that could potentially be affected by a release of a hazardous liquid. 5. They may also consider climatic conditions, availability of material, workloads, and an estimate of the relative rate of detrimental corrosion. 6. As a rule of thumb, 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 195.573 (e) if you can demonstrate that the operator’s established time frame for action is inadequate, you may cite the operator for a violation or proceed with a notice of amendment or both. 7. The operator did not take prompt remedial action in correcting the deficiencies as indicated by the corrosion control 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	Evidence of violation - § 195.573 (e) 1. Documentation showing that deficiency was discovered, including operator's records of monitoring performed and the operator's written procedures per §195.402(c)(3); and 2. Documentation showing that corrective action has not been taken; including: a. Statement of absence of action by operator or investigator; or b. Documentation showing that corrective action was not taken promptly, including operator's record of date of discovery and date of corrective action. c. Operator's corrosion control procedure, maintenance records, pipe-to-soil readings and remedial action records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.575(a)**
Section Title	**Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**
Existing Code Language	You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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 this 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. 3. Direct shorts occur when the carrier pipe and the casing are in metallic contact. 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. 5. 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. The operator's plan of action should be initiated within six months of completion of the survey. 6. 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.

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. 2. 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. 2. Documents that shows dates of pipe to soil surveys, pipe to soil and adjacent casing to soil potentials. 3. Photographs, Field data, Operator's O&M Plan, and any other documentation the inspector deems appropriate to substantiate a probable violation.
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 195**
Revision Date	**12/7/2015**
Code Section	**§195.575(b)**
Section Title	**Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**
Existing Code Language	You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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 Violation or Inadequate Procedures	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. *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. CP records, written procedures (or lack thereof), inspector observation, pictures.

Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.575(c)**
Section Title	**Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**
Existing Code Language	You must inspect and electrically test each electrical isolation to assure the isolation is adequate.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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. CP records, written procedures (or lack thereof), inspector observation, pictures.

Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.575(d)**
Section Title	**Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**
Existing Code Language	If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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 195**
Revision Date	**12/7/2015**
Code Section	**§195.575(e)**
Section Title	**Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**
Existing Code Language	If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. The operator must be aware of all electrical transmission tower footings, ground cables, or counterpoises 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. 2. If there are high voltage electrical transmission lines or substations adjacent to the pipeline, the operator must take mitigating steps to protect its pipeline from fault currents and lightning. The operator should perform an engineering analysis to determine the effects – if any – of potential fault currents and lightning on its pipeline.
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. CP records, operator’s written procedures (or lack thereof), inspector observation, pictures.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.577(a)**
Section Title	**What must I do to alleviate interference currents?**
Existing Code Language	For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. If there are any other cathodically protected underground structures that might subject the operator's pipeline system to stray currents, such as foreign pipelines, underground storage tanks, or other utility systems – including but not limited to, direct current (DC) transit systems, DC mining operations, DC welding operations, and high voltage (AC or DC) electric transmission systems – then the operator must have a written plan to identify, test for, and minimize the detrimental effects of such currents. 2. 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 procedure to identify, test for, and minimize the detrimental effects of stray current. 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. Operator's O&M manual, maintenance records.
Other Special Notations	Caution should be taken in areas of potentially high induced foreign currents, such as in overhead power corridors. High step-and-touch potentials can cause serious harm or even death. For example, NACE SP0177-2007 limits AC pipe-to-soil potentials to 15 volts.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.577(b)**
Section Title	**What must I do to alleviate interference currents?**
Existing Code Language	You must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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. 2. Cathodic protection records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.579(a)**
Section Title	**What must I do to mitigate internal corrosion?**
Existing Code Language	**General:** If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin: ADB-08-08 Proper Identification of Internal Corrosion Risk.** This advisory bulletin reminds operators of their responsibilities under 49 CFR 195.579(a) and 49 CFR 195.589(c) with respect to the identification of circumstances under which the potential for internal corrosion must be investigated.
Other Reference Material & Source	

Guidance Information	1. The operator should have a procedure to determine if the hazardous liquid or carbon dioxide being transported is corrosive. The procedure should identify the factors that influence the formation of internal corrosion. Special attention should be given to pipeline alignment features such as changes in elevation, low points, sharp bends, and dead legs that may contribute to internal corrosion by allowing water to settle out. 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. Bacterial colonies can form deposits on metal surfaces and produce organic acids that accelerate corrosion and cause localized pitting. 2. Internal corrosion is more of a concern in crude oil pipelines than in refined products pipelines. An operator should have a maintenance pigging program to ensure sludge or sediment is not preventing corrosion inhibitor from reaching the pipe wall, or allowing bacteria to form below the sediment. 3. The operator should sample the solids and liquids that are removed during their routine pigging operations for corrosivity. They should also have records to show that this information has been reviewed by qualified personnel and mitigative steps taken to reduce the corrosive atmosphere. 4. ***Kinder Morgan CO2 Company, L.P. [4-2006-5003]*** **(October 12, 2010)** – Found that the operator failed to investigate the corrosive effects of the product transported. A long-term history of no internal corrosion is not proof that the product being transported is not corrosive. Corrosion coupon records provide only a localized indication of corrosion and do not satisfy the requirement to investigate the corrosive effect of the product. CO 5. ***Kinder Morgan Energy Partners, L.P. [4-2006-5023]*** **(August 31, 2010)** – Found that the operator failed to investigate the corrosive effects of the product transported. Limited use of coupons, electric resistance probes, and ILI do not satisfy the requirement to investigate the corrosive effect of the product. CO
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not investigate the corrosive effect of the hazardous liquid or carbon dioxide on its 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. Operator's corrosion control procedures, maintenance records, review of accident investigation records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.579(b)**
Section Title	**What must I do to mitigate internal corrosion?**
Existing Code Language	**Inhibitors:** If you use corrosion inhibitors to mitigate internal corrosion, you must: (1) Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect; (2) Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors; (3) Examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding 7 ½ months.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. If the operator chooses to use inhibitors to mitigate internal corrosion, they must maintain internal corrosion control monitoring records, and take additional steps to ensure the effectiveness of its internal corrosion control monitoring program. 2. Some methods for monitoring internal corrosion are weight loss coupons, radiography, water chemistry tests, and electrical, galvanic, resistance or hydrogen probes. Special attention should be given to specific conditions, including flow characteristics and pipeline configuration (especially dead legs, sags, and overbends which are areas in a pipeline that may not be flushed or cleaned by pigging or other methods). Internal corrosion is influenced by flow regimen, pipeline configuration, operating temperature, water content, hydrogen sulfide content, oxygen content, bacteria and sediment deposits.

Examples of a Probable Violation or Inadequate Procedures	1. The operator did not use inhibitors in sufficient quantity to protect the entire pipeline system. 2. The coupons or other monitoring equipment used to monitor the internal corrosion, did not determine the effectiveness of the inhibitors. 3. The operator did not examine its monitoring coupons at least twice each calendar year but with intervals not 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. Operator’s internal corrosion control procedures, maintenance records, manufacturers’ recommended practice.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.579(c)**
Section Title	**What must I do to mitigate internal corrosion?**
Existing Code Language	**Removing pipe:** Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under § 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. Any time a pipe section is removed, the operator must perform an internal corrosion inspection. If internal corrosion is found the operator must investigate downstream and upstream beyond the removed pipe to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe. The operator must have a program for mitigation and remediation if additional internal corrosion is found on the pipeline.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not perform or does not have records to show that an internal inspection of a removed section of pipe occurred. 2. The operator found Internal corrosion during the inspection of a removed section of pipe, yet failed to determine the extent of the internal corrosion and to determine if additional pipe must be removed. The operator did not investigate circumferentially and longitudinally beyond the removed pipe to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed 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 dig records. 2. Operator program for monitoring internal corrosion. 3. Remedial and/or corrective action records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.579(d)**
Section Title	**What must I do to mitigate internal corrosion?**
Existing Code Language	Breakout tanks: After October 2, 2000, when you install a tank bottom lining in an aboveground breakout tank built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the lining in accordance with API Recommended Practice 652. However, installation of the lining need not comply with API Recommended Practice 652 on any tank for which you note in the corrosion control procedures established under §195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 652 is not necessary for the safety of the tank.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007; API Recommended Practice 652
Guidance Information	1. The operator is required to maintain procedures and records for installation of linings in aboveground breakout tanks. API Recommended Practice 652 is commonly utilized by industry. If an operator states in their procedures that they are not going to comply with this Recommended Practice, the operator's procedures established under §195.402(c)(3) must also state why compliance with certain provisions of API Recommended Practice 652 is not necessary.
Examples of a Probable Violation or Inadequate Procedures	1. The operator did not install the tank bottom lining in accordance with API Recommended Practice 652 after October 2, 2000, if the tank bottom is built to API Specification 12F, API Standard 620 or API Standard 650, or note in the corrosion control procedures established under §195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 652 was not necessary for the safety of the tank. *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 internal corrosion procedure, maintenance records.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.581(a)**
Section Title	**Which pipelines must I protect against atmospheric corrosion and what coating material may I use?**
Existing Code Language	You 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	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007; 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 water. 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, unusual environment conditions, and documented evidence of pipe wall loss.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.581(b)**
Section Title	**Which pipelines must I protect against atmospheric corrosion and what coating material may I use?**
Existing Code Language	Coating material must be suitable for the prevention of atmospheric corrosion.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice	
Other Reference Material & Source	NACE SP0169-2007
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 195**
Revision Date	**12/7/2015**
Code Section	**§195.581(c)**
Section Title	**Which pipelines must I protect against atmospheric corrosion and what coating material may I use?**
Existing Code Language	Except portions of pipelines in offshore splash zones or soil-to-air interfaces, you need not protect against atmospheric corrosion any pipeline for which you demonstrate 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	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66994, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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 195**
Revision Date	**12/7/2015**
Code Section	**§195.583(a)**
Section Title	**What must I do to monitor atmospheric corrosion control?**
Existing Code Language	You 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	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66993, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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, e.g. above ground valves, exposed water crossings, above ground piping in vaults, piping under bridges, etc. or reevaluate each pipeline that is exposed to the atmosphere, and take remedial actions whenever necessary at interval not exceeding 3 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. Operator maintenance records, pictures, pit depth and wall loss measurements.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.583(b)**
Section Title	**What must I do to monitor atmospheric corrosion control?**
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	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66993, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Industry Standards, Glossary
Guidance Information	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 195 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 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 195**
Revision Date	**12/7/2015**
Code Section	**§195.583(c)**
Section Title	**What must I do to monitor atmospheric corrosion control?**
Existing Code Language	If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by § 195.581.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66993, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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 any corrosion is found that might jeopardize the integrity of the pipeline prior to the next scheduled inspection, then more prompt action may be required under §195.581. If the corrosion is severe, remediation or replacement of the pipe or components may be necessary before coating or jacketing is performed.
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 replace corroded pipe or components in accordance with §195.581, 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. Operator maintenance records, pictures, pit depth and wall loss measurements.

Other Special Notations	Inspectors should exercise caution if areas of severe atmospheric corrosion are discovered in the field.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.585(a)**
Section Title	**What must I do to correct corroded pipe?**
Existing Code Language	**General corrosion**: If you find pipe with general corrosion and with a remaining wall thickness less than that required for the maximum operating pressure of the pipeline, you must replace the pipe. However, you need not replace the pipe if you: (1) Reduce the maximum operating pressure commensurate with the strength of the pipe needed for serviceability based on actual remaining wall thickness; or (2) Repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66993, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. Review all segments of the pipeline for internal, external or atmospheric corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure of the pipeline. The operator should have all the records on the replaced segments, repairs and appropriately reduced pressures. The sources of this information are: pig logs, exposed pipe reports, etc. Also see §195.452(h), repair criteria for IMP in HCA's.

Examples of a Probable Violation or Inadequate Procedures	1. The operator did not repair or replace a generally corroded segment of pipe. 2. The remaining strength of the pipe segment is not computed based on actual remaining wall thickness. 3. No safety related condition report filed for generally corroded 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. Repair records, pictures.
Other Special Notations	Reference section 195.571(a) for CP criterion used. Compare leak records to CP records (location). Does the operator consider IR Drop? How? 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). 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 195**
Revision Date	**12/7/2015**
Code Section	**§195.585(b)**
Section Title	**What must I do to correct corroded pipe?**
Existing Code Language	**Localized corrosion pitting:** If you find pipe that has localized corrosion pitting to a degree that leakage might result, you must replace or repair the pipe, unless you reduce the maximum operating pressure commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66993, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. Review documentation of 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	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 195**
Revision Date	**12/7/2015**
Code Section	**§195.587**
Section Title	**What methods are available to determine the strength of corroded pipe?**
Existing Code Language	Under §195.585, you may use the procedure in ASME B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines", or the procedure developed by AGA/Battelle, A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk), to determine the strength of corroded pipe based on actual remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66993, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
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 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?**
Existing Code Language	**(a)** If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion, you must follow the requirements of this section for performing external corrosion direct assessment. This section does not apply to methods associated with direct ass essment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. The ECDA process is more than performing above-ground indirect inspections. It is a four-step process that involves (1) pre-assessment analysis of all available data, (2) indirect inspection, (3) direct examination of selected indications, and (4) post-assessment analysis, including feedback and continuous improvement.
Examples of a Probable Violation or Inadequate Procedures	1. The operator fails to follow the requirements of NACE Standard SP0502–2008 or latest edition for performing the assessments and the operator must have developed a written ECDA plan that includes specific procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment. *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 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?**
Existing Code Language	**(b) The requirements for performing external corrosion direct assessment are as follows:** **(1)** General. You must follow the requirements of NACE Standard SP0502–2008 or latest edition (incorporated by reference, see §195.3). Also you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. Operators are required to follow the currently referenced NACE standard for ECDA in its entirety in addition to any additional requirements of §195.588. Additional guidance on what constitutes an effective pre-assessment can be found at Gas IMP guide material in D.01 and D.01a.

Examples of a Probable Violation or Inadequate Procedures	1. The operator fails to follow (the requirements of NACE Standard SP0502–2008 or latest edition for performing the assessments and the operator must have developed a written ECDA plan that includes specific procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment. 2. Failure to have an ECDA plan. 3. ECDA plan that does not require all of the specified documentation. 4. ECDA plan does not adequately address all of the NACE RP 0502-2002 (soon to be superseded by NACE Standard SP0502-2008, effective October 1, 2010). 5. Any requirement of NACE RP 0502-2002 (soon to be superseded by NACE Standard SP0502-2008, effective October 1, 2010) not implemented. *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. Copy of ECDA Plan 2. ECDA records
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** ***(b) The requirements for performing external corrosion direct assessment are as follows:***
Existing Code Language	**(2)** ***Pre-assessment.*** In addition to the requirements in Section 3 of NACE Standard SP0502–2008 or latest edition, the ECDA plan procedures for pre-assessment must include- **(i)** Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. NACE RP 0502-2002 (to be superseded by SP0502-2008 effective 10/1/2010) requires that operators conduct a comprehensive pre-assessment [Step 1] that includes taking historical and physical data regarding the pipeline into account when 2. Selecting indirect inspection tools. 3. Selecting and determining ECDA regions; and 4. Determining the feasibility of conducting an ECDA assessment of the pipeline. 5. Additional guidance on what constitutes an effective pre-assessment can be found at Gas IMP pre-assessment guide material in D.02, D.02a, D.02b, D.02c, and D.02d. Section 195.588 requires that more restrictive criteria be applied for initial ECDA assessments (beyond the additional requirements that NACE SP 0502-2008 places on initial ECDA assessments). Additional information and examples of “more restrictive criteria” can be found at Gas IMP pre-assessment guide material in D.02e.
Examples of a Probable Violation	1. The operator fails to follow the requirements in Section 3 of NACE Standard SP0502–2008 or latest edition. The operators written ECDA plan for

or Inadequate Procedures	pre-assessment must include: a. Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment; b. The basis on which the operator selects at least two different, but complementary, indirect assessment tools to assess each ECDA region; and c. If the operator utilizes an indirect inspection method not described in Appendix A of NACE Standard SP0502–2008 or latest edition, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method. 2. Failure to fully document the pre-assessment data. 3. Failure to document the reason for selecting indirect inspection tools. 4. Failure to justify criteria for establishing ECDA regions. 5. Failure to document the rationale of selecting ECDA regions. 6. Not requiring, performing or documenting a feasibility study. 7. Not requiring or obtaining sufficient information for a pre-assessment such as corrosion history, leak history, etc. 8. Operator only follows the additional requirements in NACE for an initial ECDA assessment, but does not apply more restrictive criteria. The operator must follow the additional requirements in both NACE and §195.588. *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. Copy of ECDA Plan. 2. Copy of Pre-assessment data for ECDA assessment. 3. No documentation on rationale for indirect inspection tool selection. 4. Not following NACE SP 0502-2008 Table 1 and 2 for ECDA region selection. 5. No documentation on rationale for ECDA region selection. 6. No feasibility study. 7. Not requiring adequate information on the pre-assessment. 8. Copy of ECDA Plan.

	9. Copy of ECDA assessment documenting the more restrictive criteria used.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**(2)** ***Pre-assessment.*** In addition to the requirements in Section 3 of NACE Standard SP0502–2008 or latest edition, the ECDA plan procedures for pre-assessment must include — **(ii)** The basis on which you select at least two different, but complementary, indirect assessment tools to assess each ECDA region.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. The concept of complementary tools means that the strengths and weakness of one tool will be complemented (or compensated) by the strengths and weaknesses of the second tool. Additional guidance can be found at Gas IMP pre-assessment guide material in D.02c.
Examples of a Probable Violation or Inadequate Procedures	1. The operator fails to follow the requirements in Section 3 of NACE Standard RP0502–2002 (to be superseded by NACE Standard SP0502-2008 effective 10/1/2010). The operators written ECDA plan for pre-assessment must include: a. Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment; b. The basis on which the operator selects at least two different, but complementary, indirect assessment tools to assess each ECDA region; and c. If the operator utilizes an indirect inspection method not described in Appendix A of NACE Standard SP0502–2008 or latest edition, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

	2. Selection of two tools that use similar technology (i.e., tools are not complimentary). 3. Failure to document the basis on which tool selection was made. *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. Copy of ECDA assessment with tool selection criteria
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**(2)** ***Pre-assessment.*** In addition to the requirements in Section 3 of NACE Standard SP0502–2008 or latest edition, the ECDA plan procedures for pre-assessment must include— **(iii)** If you utilize an indirect inspection method not described in Appendix A of NACE Standard SP0502–2008 or latest edition, you must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. Both PHMSA and NACE (see SP 0502-2008 Section 3.4.3.1 provide for using tools not listed in Appendix A. The operator must understand and demonstrate that these tools are applicable and provide meaningful and useful results. Additional guidance can be found at Gas IMP pre-assessment guide material in D.02c.
Examples of a Probable Violation or Inadequate Procedures	1. The operator fails to follow the requirements in Section 3 of NACE Standard SP0502–2008 or latest edition. The operators written ECDA plan for pre-assessment must include – a. Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment; b. The basis on which the operator selects at least two different, but complementary, indirect assessment tools to assess each ECDA region; and c. If the operator utilizes an indirect inspection method not described in Appendix A of NACE Standard SP0502–2008 or latest edition, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

	2. Failure to have sufficient justification that tools are equivalent or superior to tools listed in Appendix A with regard to finding and categorizing indications. 3. Not having acceptable procedures for using the tools. *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. Copy of justification of using tools not listed in NACE SP 0502-2008 Appendix A including validation of tools, applicability, tool procedures and how data will be utilized.
Other Special Notations	Both PHMSA and NACE (see SP 0502-2008 Section 3.4.3.1) provide for using tools not listed in Appendix A. The operator must understand and demonstrate that these tools are applicable and provide meaningful and useful results. Additional guidance can be found at Gas IMP pre-assessment guide material in D.02c.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**(3)** ***Indirect examination*****.** In addition to the requirements in Section 4 of NACE Standard SP0502–2008 or latest edition, the procedures for indirect examination of the ECDA regions must include— **(i)** Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;
Origin of Code	
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. The indirect inspection step [Step 2] is where the operator uses the two or more indirect inspection tools over the entire ECDA region, classifies the indications (using the NACE terminology of severe, moderate and minor indications) and aligns the indications and integrates the indirect inspection data with the pre-assessment data, such as foreign line crossings and areas of encroachment. The physical spacing between each tool reading must be sufficiently close so that indications can be readily identified. Most operators set up a "severity chart" to document the methods they use to classify the indications so they can then be integrated and aligned with other indirect inspection tool results and pre-assessment data. Also see Gas IMP indirect inspection guide material in D.03, D.03a, and D.03 for additional guidance. Operators must follow all of the additional NACE requirements for an initial ECDA assessment plus must document additional more restrictive criteria per §195.588. See Gas IMP indirect inspection guide material in D.03c for additional guidance.

Examples of a Probable Violation or Inadequate Procedures	1. The operators' written plan fails to address any of the requirements in Section 4 of NACE Standard SP0502–2008 or latest edition or the specific requirements as listed (above) regarding scheduling, criteria, definitions, approaches and procedures. 2. Not documenting or physically marking the start and end point of each ECDA region. 3. Not covering all of each region with each indirect inspection tool. 4. Not aligning or overlaying the results of each indirect inspection tool 5. Not having documentation on how conflicting data from each inspection tool is handled. 6. Operator only follows the additional requirements in NACE for an initial ECDA assessment, but does not apply more restrictive criteria. The operator must follow the additional requirements in both NACE and §195.588. *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. Copy of ECDA Plan 2. Copy of ECDA assessment documenting the more restrictive criteria used.
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**(3)** ***Indirect examination*****.** In addition to the requirements in Section 4 of NACE Standard SP0502–2008 or latest edition, the procedures for indirect examination of the ECDA regions must include— **(ii)** Criteria for identifying and documenting those indications that must be considered for excavation and direct examination, including at least the following: **(A)** The known sensitivities of assessment tools; **(B)** The procedures for using each tool; and **(C)** The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. This task in NACE SP0502-2008 is handled under the Direct Examination step [Step 3] but in both 192 and 195 it is listed in Step 2. This requires the operator to set up a methodology to determine which indications discovered by the indirect inspection tools must be excavated using the NACE prioritization terminology of immediate (which only means it has the highest priority), scheduled and monitored indications. See Gas IMP indirect inspection guide material in D.03b for additional guidance.

Examples of a Probable Violation or Inadequate Procedures	1. The operators' written plan fails to address any of the requirements in Section 4 of NACE Standard SP0502–2008 or latest edition or the specific requirements as listed (above) regarding scheduling, criteria, definitions, approaches and procedures. 2. Failure to document or consider the sensitivity of the indirect inspection tools. 3. Failure to document an approach to be used for decreasing the spacing or intervals between tool readings when locating an indication. *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. Copy of ECDA Plan. 2. Copy of ECDA assessment including procedures for each indirect inspection tool. 3. Copy of ECDA assessment which documents how physical spacing of indirect inspection tools should be changed to locate an indication.
Other Special Notations	NACE Standard SP0502-2008, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology" (reaffirmed March 20, 2008).

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing code language	**(3)** ***Indirect examination*****.** In addition to the requirements in Section 4 of NACE Standard SP0502–2008 or latest edition, the procedures for indirect examination of the ECDA regions must include— **(iii)** For each indication identified during the indirect examination, criteria for— **(A)** Defining the urgency of excavation and direct examination of the indication and; **(B)** Defining the excavation urgency as immediate, scheduled, or monitored.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. This requirement in NACE is in Step 3 but in both 192 and 195 is in Step 2. Most operators use a matrix chart or some methodology to move from classification (severe, moderate, minor) to prioritization for excavation (immediate, scheduled, monitored). They typically make it a three by three chart with one tool counting more than another, such as a CIS being weighed more heavily than AC Attenuation or ACVG. Some operators also factor in past corrosion history, third party damage and foreign line crossings (such as a moderate indication at a foreign line crossing becomes an immediate if the excavation was not witnessed). See Gas IMP guide material in D.04 for additional guidance.
Examples of a Probable Violation or Inadequate Procedures	1. The operators' written plan fails to address any of the requirements in Section 4 of NACE Standard RP0502–2002 to be superseded by NACE Standard SP0502-2008 effective 10/01/2010 or the specific requirements as listed (above) regarding scheduling, criteria, definitions, approaches and procedures. 2. Failure to define criteria for urgency of direct examination. 3. Criteria does not comply with NACE

	4. Failure to take into accoun	some pre-assessment data such determining the urgency of excavation of an indication. *Depending on the circumstances, some of the examples listed procedures, and not probable violations. Thus, the enforceme Amendment and not a Notice of Probable Violation or a Warni provides guidance on selecting the appropriate enforcement ac*
Examples of Evidence		1. Copy of ECDA Plan. 2. Copy of ECDA assessment that has encroachment data whi urgency of excavations.
Other Special Notations		NACE Standard SP0502-2008, Standard Practice, “Pipeline Ex Methodology” (reaffirmed March 20, 2008).

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**(3)** ***Indirect examination*****.** In addition to the requirements in Section 4 of NACE Standard SP0502–2008 or latest edition, the procedures for indirect examination of the ECDA regions must include— **(iv)** Criteria for scheduling excavations of indications in each urgency level.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. The criterion for scheduling the excavations is in NACE SP0502-2008 Section 5.10 which requires immediate indications to have the highest priority followed by scheduled indications. See Gas IMP guide material in D.04a for additional guidance.
Examples of a Probable Violation or Inadequate Procedures	1. The operators' written plan fails to address any of the requirements in Section 4 of NACE Standard SP0502–2008 or latest edition or the specific requirements as listed (above) regarding scheduling, criteria, definitions, approaches and procedures. Failure to document criteria for scheduling excavation and direct examination. *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. Copy of ECDA Plan.
Other Special Notations	NACE Standard SP0502-2008, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology” (reaffirmed March 20, 2008).

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**(4)** ***Direct examination*****.** In addition to the requirements in Section 5 of NACE Standard SP0502–2008 or latest edition, the procedures for direct examination of indications from the indirect examination must include— **(i)** Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. In the Direct Examination Step (Step 3) NACE requires that prioritization of the indication be performed (already required by 195.588 in Step 2) and that certain data be taken during the excavation. Section 5.10 in NACE SP0502-2008 gives the requirements for what indications must be excavated and directly examined for both initial and subsequent ECDA assessments. Even with no immediate or scheduled indications, a minimum of two indications must be excavated for initial ECDA assessments (one on subsequent assessments). In addition a root cause analysis of any corrosion found must be undertaken along with a process evaluation to determine if ECDA is still a suitable method of assessing this pipeline. The remaining strength of any indication found to have corrosion must be determined. Where corrosion has been found, operators are also required to undertake effective and timely mitigation of the root causes of the corrosion and document these actions. Once all of the data on the corrosion found is obtained the operator must compare the 'as found' condition with the 'as expected' and make adjustments to their criteria for classification and prioritization to take the differences into account. 2. For the initial ECDA assessment there can be no down grading of the priority based on these results. See Gas IMP direct examination guide material in D.04 for additional guidance. Operators must follow all of the additional NACE requirements for an initial ECDA assessment plus must document additional more restrictive

	criteria per §195.588. See Gas IMP direct examination guide material in D.04i for additional guidance.
Examples of a Probable Violation or Inadequate Procedures	1. The operators' written plan fails to address the specific requirements in Section 5 of NACE Standard SP0502–2008 or latest edition; and does not specify all criteria and procedures required. 2. Failure to perform or document a root cause analysis. 3. Failure to perform or document the process evaluation. 4. Failed to have a requirement that, for initial ECDA assessment, there can be no down grading of an indication's priority. 5. Failure to perform enough direct examinations to meet the requirements of Section 5.10 in NACE. 6. Operator only follows the additional requirements in NACE for an initial ECDA assessment, but does not apply more restrictive criteria. The operator must follow the additional requirements in both NACE and §195.588. *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. Copy of ECDA assessment that does not contain root cause analysis. 2. Copy of ECDA assessment that shows a down grading of a priority on an initial assessment. 3. Copy of the ECDA assessment dig list showing the ECDA region, the priority of the indication, the location of the excavation and the locations of the validation excavations. 4. Copy of ECDA Plan 5. Copy of ECDA assessment documenting the more restrictive criteria used.
Other Special Notations	NACE Standard SP0502-2008, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology" (reaffirmed March 20, 2008).

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**(4) *Direct examination***. In addition to the requirements in Section 5 of NACE Standard SP0502–2008 or latest edition, the procedures for direct examination of indications from the indirect examination must include— **(ii)** Criteria for deciding what action should be taken if either: **(A)** Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE Standard SP0502–2008 or latest edition provides guidance for criteria); or **(B)** Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE Standard SP0502–2008 or latest edition provides guidance for criteria).
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. When significant and serious corrosion defects are found, operators need to determine if ECDA is a suitable method of assessment based on the actual findings and the result of a root cause analysis (for example if shielding coating is found or interference currents). Operators must also assume that if one area has significant corrosion others areas will probably have similar corrosion and must act accordingly. See Gas IMP direct examination guide material in D.04c, D.04d, and D.04 for additional guidance.
Examples of a Probable Violation or Inadequate	1. The operators' written plan fails to address the specific requirements in Section 5 of NACE Standard SP0502–2008 or latest edition; and does not specify all criteria and procedures required.

Procedures	2. Failure to perform or document a root cause analysis. 3. Failure to have, in the ECDA plan, a requirement that other methods of assessment must be used if ECDA is determined not to be a suitable method per the root cause analysis. *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. Copy of ECDA Plan. 2. Copy of ECDA assessment that does not show that a root cause analysis was performed or documented.
Other Special Notations	NACE Standard SP0502-2008, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology" (reaffirmed March 20, 2008).

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**4) *Direct examination*.** In addition to the requirements in Section 5 of NACE Standard SP0502–2008 or latest edition, the procedures for direct examination of indications from the indirect examination must include – **(iii)** Criteria and notification procedures for any changes in the ECDA plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. Operators must have provisions to take lessons learned during an ECDA assessment and apply them to future ECDA assessments by changing their ECDA plan accordingly. See Gas IMP direct examination guide material in D.04e and D.04g for additional guidance.
Examples of a Probable Violation or Inadequate Procedures	1. The operators' written plan fails to address the specific requirements in Section 5 of NACE Standard SP0502–2008 or latest edition; and does not specify all criteria and procedures required. 2. Failure to include a management of change process in the ECDA plan. 3. Failure to apply knowledge and lessons learned during one ECDA assessment and change the ECDA plan to take the knowledge into account in subsequent ECDA assessments. *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. Copy of ECDA Plan. 2. Copy of Management of Change Plan. 3. Copy of ECDA assessment that does not show that lessons learned were either applied or noted for future ECDA assessments.
Other Special Notations	NACE Standard SP0502-2008, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology” (reaffirmed March 20, 2008).

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**(4) Direct examination.** In addition to the requirements in Section 5 of NACE Standard SP0502–2008 or latest edition, the procedures for direct examination of indications from the indirect examination must include— **(iv)** Criteria that describe how and on what basis you will reclassify and re-prioritize any of the provisions specified in Section 5.9 of NACE Standard SP0502–2008 or latest edition.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. Per NACE, for initial ECDA assessments there cannot be any down grading of the priority of indications. For subsequent assessments both down grading and up grading is allowed. See Gas IMP direct examination guide material in D.04f for additional guidance.
Examples of a Probable Violation or Inadequate Procedures	1. The operators' written plan fails to address the specific requirements in Section 5 of NACE Standard SP0502–2008 or latest edition; and does not specify all criteria and procedures required. 2. Failure to specify in the ECDA plan that the priorities of indications cannot be downgraded on initial ECDA assessments. *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. Copy of ECDA Plan
Other Special Notations	NACE Standard SP0502-2008, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology” (reaffirmed March 20, 2008).

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**(5)** ***Post assessment and continuing evaluation***. In addition to the requirements in Section 6 of NACE Standard SP 0502–2008 or latest edition, the procedures for post assessment of the effectiveness of the ECDA process must include— **(i)** Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in pipeline segments.
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. The post assessment step (Step 4) has several important requirements such as performing process validation excavations and direct examinations, determining the reassessment interval using ½ of the remaining life, using a default corrosion rate for calculating the remaining life if a rate is not known and to determine the overall effectiveness of the ECDA process. This is the only step within the ECDA process where §195.588 does **NOT** require more restrictive criteria on initial ECDA assessments. See Gas IMP post assessment guide material in D.05a, D.05c and D.05d for additional guidance. NACE provides several examples of determining the overall effectiveness of the ECDA process. One very import measure is the validation excavation and direct examination (for initial ECDA assessment two excavations are necessary). When the results of these direct examinations are not as expected it may show that the ECDA process is not suitable for this pipeline or that it was not performed properly. Other criteria for evaluating the long term effectiveness of the ECDA must also be included in the ECDA plan. See Gas IMP post assessment guide material in D.05c for additional guidance.
Examples of a Probable Violation or Inadequate Procedures	1. The operators' written plan does not address the requirements in Section 6 of NACE Standard UP 0502–2002 or latest edition. The written plan must include specific measures for evaluating the long-term effectiveness of ECDA and written criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the pipeline segment at an interval less than that specified.

	2. Failure to perform all required (or any) validation excavations and direct examinations. 3. Failure to use the NACE mandated default corrosion rate when other data is not available. 4. Setting the re-assessment interval past the maximum allowed in Part 195 or 195. 5. Failure to document the lessons learned and applying them to subsequent ECDA assessments. 6. Failure to document the overall effectiveness of the ECDA process. 7. Failure to properly calculate the reassessment interval properly. 8. Failure to perform the correct number of validation excavations and direct examinations on initial ECDA assessments. 9. Failure to document the long term effectiveness criteria as specified in NACE. *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. Copy of ECDA assessment dig list 2. Copy of ECDA assessment re-assessment intervals with calculations and corrosion growth rate specified 3. Copy of ECDA assessment re-assessment intervals and the maximum interval allowed under 195 4. Copy of ECDA assessment that does not have effectiveness metrics 5. Copy of ECDA assessment dig sheet with validation excavations noted
Other Special Notations	NACE Standard SP0502-2008, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology” (reaffirmed March 20, 2008).

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§ 195.588**
Section Title	**What standards apply to direct assessment?** **(b) The requirements for performing external corrosion direct assessment are as follows:**
Existing Code Language	**(5)** ***Post assessment and continuing evaluation***. In addition to the requirements in Section 6 of NACE Standard SP 0502–2008 or latest edition, the procedures for post assessment of the effectiveness of the ECDA process must include— **(ii)** Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the pipeline segment at an interval less than that specified in Sections 6.2 and 6.3 of NACE Standard SP0502–2008 or latest edition (see appendix D of NACE Standard SP0502–2008 or latest edition).
Origin of Code	
Last Amendment	[Amdt. 195–85, 70 FR 61576, Oct. 25, 2005]
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	
Guidance Information	1. The operators ECDA plan must have provisions for identifying some conditions that may require that a reassessment be performed at an interval less than those specified in either NACE Section 6.3 or 195. See Gas IMP post assessment guide material in D.05a, D.05b for additional guidance.
Examples of a Probable Violation or Inadequate Procedures	1. The operators' written plan does not address the requirements in Section 6 of NACE Standard UP 0502–2002 or latest edition. 2. The written plan must include specific measures for evaluating the long-term effectiveness of ECDA and written criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the pipeline segment at an interval less than that specified. 3. Failure to include provisions for requiring shorter reassessment intervals based on findings from evaluation of conditions discovered during direct examinations.

	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. Copy of ECDA Plan 2. Copy of ECDA assessment not showing documentation that an evaluation of conditions found was performed relating to re-assessment intervals
Other Special Notations	NACE Standard SP0502-2008, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology” (reaffirmed March 20, 2008).

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.589(a)**
Section Title	**What corrosion control information do I have to maintain?**
Existing Code Language	You must maintain current records or maps to show the location of: (1) Cathodically protected pipelines. (2) Cathodic protection facilities, including galvanic anodes, installed after 30 days after the rule's effective date (1/28/2002). (3) Neighboring structures bonded to cathodic protection systems.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66993, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. The operator is required to maintain updated records or maps of all its cathodically protected pipelines. The operator is required to records or maps of its cathodic protection facilities and galvanic anodes installed after January 28, 2002. CP facilities include rectifiers, test stations, bonds, etc.
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. O&M Manual, Maintenance records, maps, inspector's observations.

Other Special Notations	An operator may choose to isolate and separately cathodically protect segments of its pipeline system. For example, pump station piping may be isolated and separately cathodically protected from the pipeline. The operator should have records to show when this is done.

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.589(b)**
Section Title	**What corrosion control information do I have to maintain?**
Existing Code Language	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	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66993, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	NACE SP0169-2007
Guidance Information	1. The operator need not include the specific distance in its records.
Examples of a Probable Violation or Inadequate Procedures	
Examples of Evidence	
Other Special Notations	

Enforcement Guidance	**CORROSION Part 195**
Revision Date	**12/7/2015**
Code Section	**§195.589(c)**
Section Title	**What corrosion control information do I have to maintain?**
Existing Code Language	You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to §195.569, §195.573(a) and (b), and §195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.
Origin of Code	HLPLSA 1979
Last Amendment	Amdt 195-73, 66 FR 66993, Dec. 27, 2001
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin: ADB-08-08 Proper Identification of Internal Corrosion Risk.** This advisory bulletin reminds operators of their responsibilities under 49 CFR 195.579(a) and 49 CFR 195.589(c) with respect to the identification of circumstances under which the potential for internal corrosion must be investigated.
Other Reference Material & Source	

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, has been interpreted correctly and demonstrate that the operator's corrosion control systems for atmospheric, internal, and external corrosion are 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 §195.569, §195.573(a) and (b), and §195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service. 3. ***Navajo Nation Oil & Gas Company, Inc. [4-2006-5029]*** **(March 17, 2010)** – Found that operator failed to maintain records of corrosion monitoring in sufficient detail to demonstrate the adequacy of corrosion control measures as required. Item 1A: Invoices showing that the pipe had been inspected and cleaned by a painting contractor do not demonstrate compliance with the record-keeping requirement for inspecting for atmospheric corrosion (required by § 195.583). Item 1B: Photographs of a section of removed pipe are not sufficient to demonstrate record-keeping of inspection of exposed pipe for external corrosion. Item 1C: An inspection form filled out 3 years after the internal inspection of a piece of removed pipe does not satisfy the record-keeping requirement. CP 4. ***Sunoco Pipeline L.P. [4-2007-5040]*** **(December 16, 2010)** – A list of records provided by the operator does not prove that those records actually exist and have been maintained in accordance with the regulation. CP 5. ***International-Matex Tank Terminals [1-2008-5006]*** **(December 23, 2009)** – Found that the operator failed to maintain a record of an inspection of removed pipe for internal corrosion. The operator stated that it was only partial owner of the pipeline at the time of the inspection of the removed pipe, and that the other owner was responsible for maintaining the records. However, the record maintenance requirement in § 195.589(c) applies to all "operators," including any company or person with partial ownership. CO
Examples of a Probable Violation or Inadequate Procedures	1. The operator has not maintained 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 for the specified retention period. *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, maps, inspector's observations.

Other Special Notations	