

Guidance on Implementing Corrosion Control Methodologies to Align with New PHMSA Regulatory Procedures

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Guidance on Implementing Corrosion Control Methodologies to Align with New PHMSA Regulatory Procedures

Foreword, Scope, Rationale	4
Referenced Standards and Other Consensus Documents	5
Section 1 General	5
Section 2 Definitions	6
Section 3 Permits	7
Section 4 Installation of Pipe in a Ditch	7
4.1 PHMSA Regulation § 192.319 Installation of Pipe in a Ditch	7
4.2 Coating Assessment: § 192.319(d)	8
4.3 Utilizing Other Technology to Conduct Coating Assessment: § 192.319(f)	9
Section 5 External Corrosion Control: Protective Coating	9
5.1 PHMSA Regulation § 192.461 External Corrosion Control: Protective Coating	9
5.2 Coating Assessment: § 192.461(f)	10
5.3 Utilizing Other Technology to Conduct Coating Assessment: § 192.461(g)	11
5.4 Remedial Action Plan: § 192.461(h)	11
Section 6 External Corrosion Control: Monitoring and Remediation	12
6.1 PHMSA Regulation § 192.465 External Corrosion Control: Monitoring and Remediation	12
6.2 Repair Timing Requirements: § 192.465(d)	13
6.3 Determine Extent of Inadequate Cathodic Protection: § 192.465(f)	14
Section 7 External Corrosion Control: Interference Currents	15
7.1 PHMSA Regulation § 192.473 External Corrosion Control: Interference Currents	15
7.2 Interference Survey and Analysis: §§ 192.473(c)(1) & 192.473(c)(2)	16
7.3 Remediation: §§ 192.473(c)(3) & 192.473(c)(4)	17
7.4 DC Interference: § 192.473(c)	17
Section 8 Internal Corrosion Control: Onshore Transmission Monitoring and Mitigation	17
8.1 PHMSA Regulation § 192.478 Internal Corrosion Control: Onshore Transmission Monitoring and Mitigation	17
8.2 Potentially Corrosive Constituents: § 192.478(a)	18
8.3 Monitoring and Mitigation Program: § 192.478(b)	18
8.4 Monitoring and Mitigation Program: § 192.478(c)	19
Section 9 Remedial Measures: Transmission Lines	20
9.1 PHMSA Regulation § 192.485 Remedial Measures: Transmission Lines	20
9.2 Calculating Remaining Strength: § 192.485(c)	20

Section 10 Transmission Lines: Repair Criteria for Onshore Transmission Pipelines 20

 10.1 PHMSA Regulation § 192.714 Transmission Lines: Repair Criteria for
 Onshore Transmission Pipelines.....21

 10.2 Metal Loss: § 192.714(d)(2)(iv) & § 192.714(d)(2)(v).....21

Other Referenced Documents 21

TABLES

Table 1 Minimum Safety Factors for B31G and RSTRENG Calculations 21

Foreword

In August 2022, the United States’ Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) revised the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission lines. PHMSA expects the new requirements will reduce the frequency and consequences of failures and incidents involving onshore natural gas transmission pipelines through earlier detection of threats to pipeline integrity, including those resulting from corrosion or extreme weather events. Additionally, revisions to the regulations address several other areas, including management of change processes, corrosion control, and criteria to repair pipelines. New corrosion control regulations were incorporated into the following sections of the United States Code of Federal Regulations (CFR) Title 49, Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards:¹ 192.319, 192.461, 192.465, 192.473, and 192.478. Additionally, revisions to Sections 192.485 and 192.714 include remedial measures for transmission lines impacted by corrosion.

PHMSA’s Regulation Identifier Number (RIN) 2137-AF39 entitled “Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments” (also known as RIN 2 or the Gas Mega Rule)² increases pipeline safety regulatory requirements in 49 CFR 192 for operations, maintenance and integrity management.

Scope

This Guide provides guidance for United States pipeline operators to assist with the implementation of corrosion control methodology requirements for onshore gas transmission as required in Part 2 of the PHMSA Gas Mega Rule. This Guide can also be used by pipeline operators in other countries as guidance.

Rationale

Pipeline operators desired an industry consensus document to guide operators on how to implement the new regulations. In addition to providing guidance on corrosion control, this Guide also addresses some operations, maintenance, and integrity management sections of the PHMSA Gas Mega Rule. Since operators need to incorporate the RIN 2 requirements into systems, processes, and procedures to ensure compliance, this AMPP Guide recommends procedures to comply with the new corrosion requirements using proven tools and techniques to safely monitor and protect Operators’ assets.

Referenced Standards and Other Consensus Documents

Unless specifically dated, the latest edition, revision, or amendment of the documents listed in the table below shall apply.

AMPP/NACE/SSPC, www.ampp.org:	
NACE/ASTM G193	Standard Terminology and Acronyms Relating to Corrosion
AMPP SP21443	Coating Systems (External) for Pipeline Trenchless Crossings
NACE TM0109	Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition
NACE SP0502-2008	Pipeline External Corrosion Direct Assessment Methodology
NACE SP0502-2010	Pipeline External Corrosion Direct Assessment Methodology
NACE SP0207	Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines
NACE TM0497	Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems
NACE SP21424	AC Corrosion on Cathodically Protected Pipelines: Risk Assessment, Mitigation, and Monitoring
NACE SP0169	Control of External Corrosion on Underground or Submerged Metallic Piping Systems
NACE SP0106-2018	Control of Internal Corrosion in Steel Pipelines and Piping Systems
NACE SP0110	Wet Gas Internal Corrosion Direct Assessment Methodology for Pipelines
NACE TR3T199	Techniques for Monitoring and Measuring Corrosion and Related Parameters in Field Applications
NACE SP0113	Pipeline Integrity Management: Methods Selection and Implementation
American Society of Mechanical Engineers (ASME), www.asme.org:	
ASME B31G	Manual for Determining the Remaining Strength of Corroded Pipelines

Note: Operators should incorporate any specific version referenced by PHMSA. If a specific version is not mentioned, consider using the most recent version.

AMPP Guides present the user with information about alternative procedures, materials, or technologies that enable the user to select the best option for a specific use. They may contain recommendations to assist the user to make an informed decision based on the desired outcome. Information on health, safety, and environmental issues may be included, but the user is responsible for knowledge of and compliance with appropriate national and local regulations.

Section 1: General

For ease of use and to prevent users from having to consult the CFR, this Guide reproduces the content of each pertinent section of the new PHMSA Gas Mega Rule as of July 17, 2023 in **red text**, and highlights in *italics* the changes made as a result of RIN 2. In some sections of this Guide, the entire rule change is not reproduced and thus the paragraph numbering may seem out of sequence. Recommendations for implementation are described in the subsequent paragraphs following the Rule.



Section 2: Definitions

The definitions of many of the corrosion-related terms used in this standard may be found in NACE/ASTM G193. With the exception of the definition of horizontal directional drilling, the following definitions are reproduced from 49 CFR § 192.3.

Close Interval Survey: A series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipe-line that may cause corrosion and for the purpose of quantifying voltage drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.

Distribution Center: The initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example:

- (1) At a metering location;
- (2) A pressure reduction location; or
- (3) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.

Dry Gas or Dry Natural Gas: Gas above its dew point and without condensed liquids.

Hard Spot: An area on steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV10).

Horizontal Directional Drilling (HDD): A steerable trenchless method of installing underground pipe (see AMPP SP21443).

In-line Inspection (ILI): An inspection of a pipeline from the interior of the pipe using an inspection tool also called intelligent or smart pigging. This definition includes tethered and self-propelled inspection tools.

In-line Inspection Tool or Instrumented Internal Inspection Device: An instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an intelligent or smart pig.

Transmission Line: A pipeline or connected series of pipelines, other than a gathering line, that:

- (1) Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center;
- (2) Has a maximum allowable operating pressure (MAOP) of 20 percent or more of the pipeline's specified minimum yield strength (SMYS);
- (3) Transports gas within a storage field; or
- (4) Is voluntarily designated by the operator as a transmission pipeline.

Note: For transmission line. A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

Underground Natural Gas Storage Facility (UNGSF) or underground storage system or underground storage pool: A gas pipeline facility that stores natural gas underground incidental to the transportation of natural gas, including:

- (1)
 - (i) A depleted hydrocarbon reservoir;
 - (ii) An aquifer reservoir; or
 - (iii) A solution-mined salt cavern.
- (2) In addition to the reservoir or cavern, a UNGSF includes injection, withdrawal, monitoring, and observation wells; wellbores and downhole components; wellheads and associated wellhead piping; wing-valve assemblies that isolate the wellhead from connected piping beyond the wing-valve assemblies; and any other equipment, facility, right-of-way, or building used in the underground storage of natural gas.

Section 3: Permits

Operators should provide their interpretation of permits that would be required to accomplish the installation of remedial measures. Examples of permits, or multiple permits, may include items that may delay the completion of a project and be out of the control of the operator. Specific examples may include traditional permits from road, county, state, or federal agencies, right-of-way (ROW) acquisition, permission from landowners to complete work, environmental or cultural permits, biological surveys, obtaining physical access, system availability, or receipt of procured material.

The application and receipt dates for the permit should be documented as part of an operator's procedures. Additionally, causes for delays in receipt of the permit should be documented along with pertinent supporting documentation and correspondence with the permitting agency.

If no permit is required to complete work, the repair should be completed as soon as practical within the regulatory timeframe. However, this would not shorten the completion date requirements for the repair.

Section 4: Installation of Pipe in a Ditch

4.1 PHMSA Regulation § 192.319 Installation of Pipe in a Ditch

- “(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.
- (b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:
 - (1) Provides firm support under the pipe; and
 - (2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.
- (c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.
- (d) *Promptly after a ditch for an onshore steel transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.*
- (e) *An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (d) of this section.*
- (f) *An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dB μ V for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.*