ARK Engineering & Technical Services, Inc.

AC CORROSION – ISSUES AFFECTING OPERATORS TODAY

By

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Introduction – AC Background

- Although not all aspects of the AC Corrosion mechanism have been fully clarified, experience has reached a level from which general guidelines have been developed.
- AC Corrosion Risk Assessment, AC corrosion mitigation , and AC corrosion monitoring.

Overview

- NACE - Task Group 430 – Issued a document titled: “Alternating Current Corrosion on Cathodically Protected Pipelines: Risk Assessment, Mitigation, and Monitoring” in May 2018.
- NACE SP21424-2018
- This standard practice presents guidelines and procedures for use during risk assessment, mitigation, and monitoring.

NACE Standard SP21424-2018

- AC Corrosion on a cathodically protected underground pipeline is commonly the result of a combined action of the AC voltage, the CP conditions, a coating defect, and the chemical and physical conditions of the soil.
- If the AC component is removed or limited, the corrosion will be mitigated.

NACE Standard SP21424-2018

- AC Corrosion is also influenced by DC current. It can also be reduced by adjusting the DC component through the CP system.
- An AC Corrosion evaluation process includes an analysis to develop the following strategies:

Evaluation Process

- Analysis – Risk Assessment
- Mitigation Strategy
- Monitoring Strategy
- On-going monitoring to determine safe or unsafe conditions

- Used for new pipelines, new interference source, or existing pipelines

AC Interference vs. AC Corrosion

- Inductive and conductive effects as a result of AC current flowing in electric circuits.
- AC voltage and currents are induced upon the pipeline.
- Where these AC currents leave the pipeline through coating defects, they can cause AC corrosion effects.
- The intensity is measured in A/m2

Current Changes in Regulations

- It’s called the “Mega” Rule for a reason. It is the most comprehensive and sweeping change in regulations the gas pipeline industry has seen since 49-CFR 192 was introduced. It’s so large, in fact, it had to be broken into three parts.

WHY IS THE MEGA RULE NEEDED

to improve the safety of onshore gas transmission lines

KEY DRIVERS FOR CHANGE

SAN BRUNO, CA: September 9, 2010 | 30” Pipeline Failure (PG&E)

- **8 people killed, 60+ injured, 38 homes destroyed, 70 homes damaged**
- **Root cause of incident: Inadequate integrity management (IM) program that failed to detect and repair or remove the defective pipe section.**

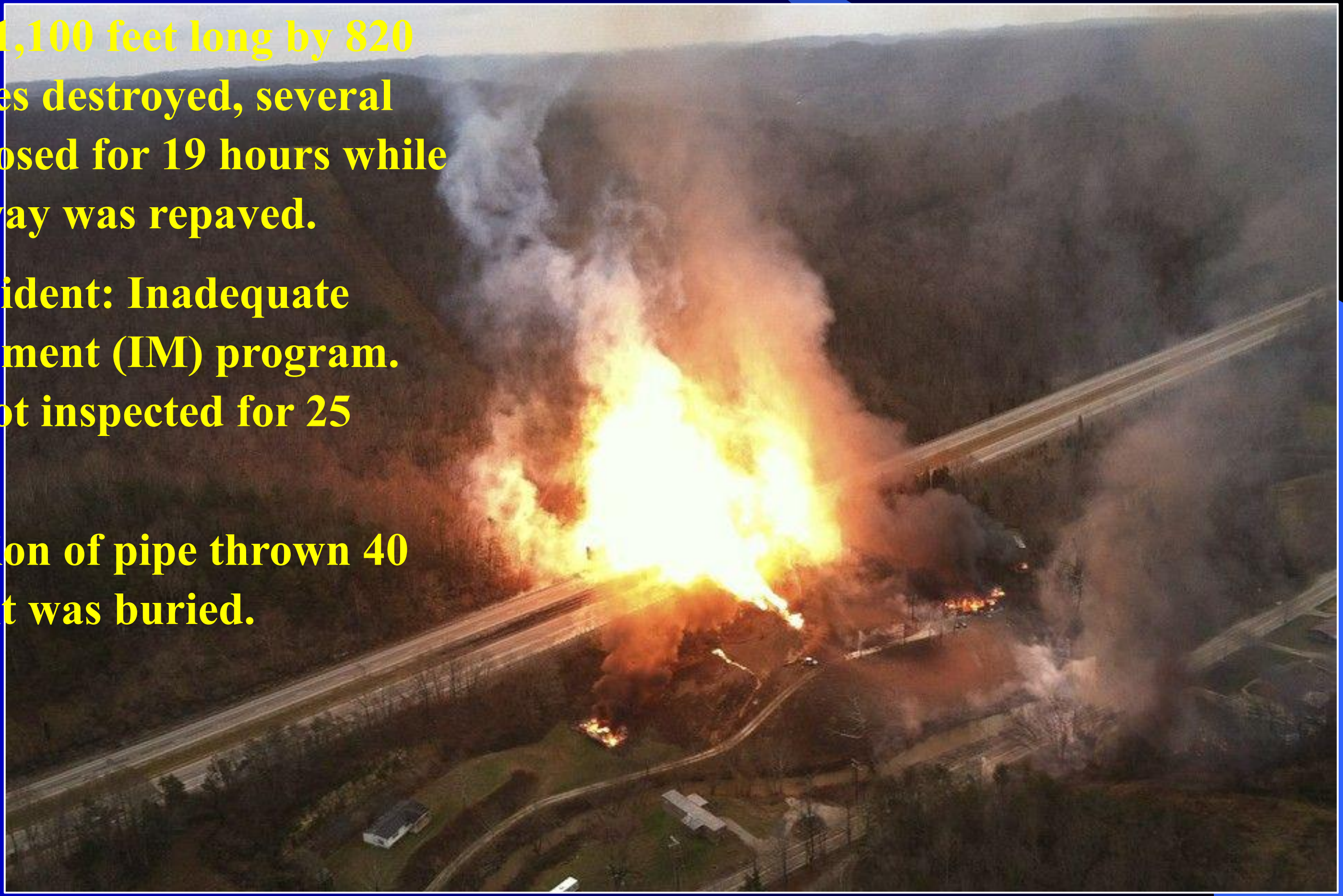
- 28-foot-long section of pipe thrown approx. 100 feet from where it was buried.

WHY IS THE MEGA RULE NEEDED

to improve the safety of onshore gas transmission lines

SISSONVILLE, WV: December 11, 2012
20" Pipeline Failure (Columbia Gas)

- **Damaged ROW 1,100 feet long by 820 feet wide. 3 houses destroyed, several damaged. I-77 closed for 19 hours while 800 feet of roadway was repaved.**
- **Root cause of incident: Inadequate integrity management (IM) program. Corroded pipe not inspected for 25 years.**
- **20-foot-long section of pipe thrown 40 feet from where it was buried.**



PHMSA MEGA RULE PART 1

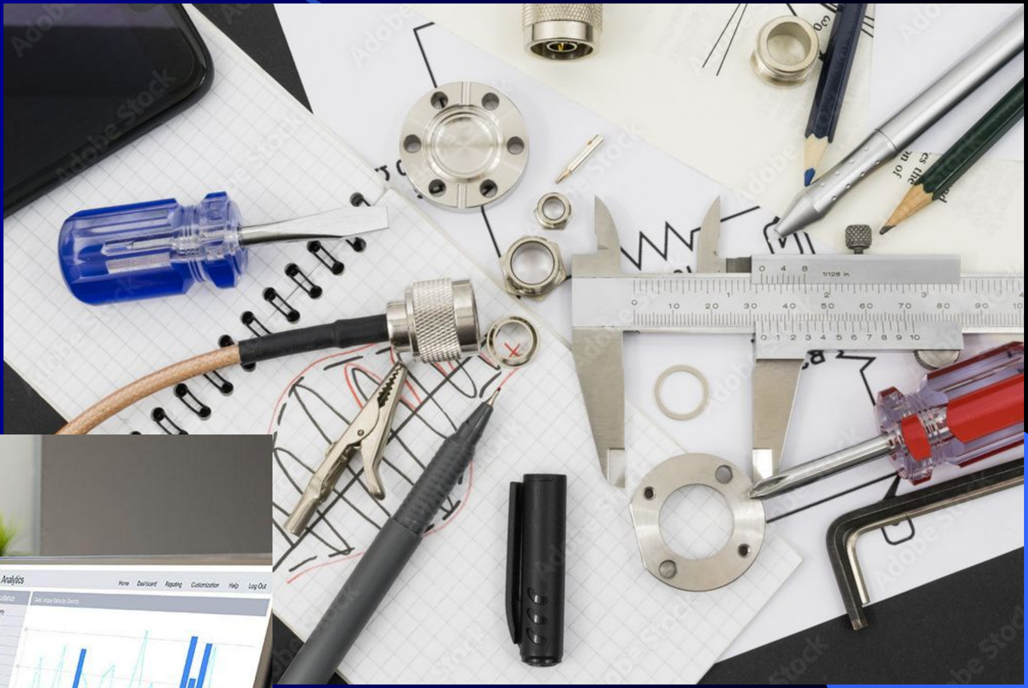
- OVERVIEW
  - Part 1 contains changes to the regulations for gas transmission lines and new requirements for the verification of pipeline materials. This part of the rule aims to improve safety with transportation and operation of onshore gas transmission pipelines.

MEGA Rule: Part 1

- TIMELINE

July 1, 2020	Rule went into effect
December 30, 2020	Rule is officially enforced
July 1, 2021	Companies need a plan in place to verify MAOP and identify MCAs
July 3, 2028	50% of MAOP verification must be complete
July 2, 2035	100% of MAOP verification must be complete; must have plan in place to regularly assess MCAs

Operators have had to do their due diligence and dig to find records



PHMSA MEGA RULE PART 3 “GAS GATHERING RULE”

- OVERVIEW

Mega Rule Part 3 focuses on PHMSA’s oversight reach.

Previously their authority covered transmission and some 11,661 miles of onshore gathering pipeline, but this new regulation extends coverage practically from the first valve off the production facility, bringing an estimated additional 426,000 miles of gas pipeline under PHMSA’s jurisdiction.

Of this mileage, PHMSA estimates 90,863 miles will classify as Type C gathering, which qualifies for more stringent regulatory treatment.

PHMSA MEGA RULE PART 3 “GAS GATHERING RULE”

KEY HIGHLIGHTS

- Emergency Orders: New requirements for emergencies that provide PHMSA with the authority to issue emergency orders. This will more easily allow PHMSA to address imminent hazards that could impact the industry, such as unsafe conditions or faulty components used on a pipe.
- Type C lines: Large diameter, high-pressure gathering lines are susceptible to the same types of integrity threats as transmission pipelines, including corrosion, excavation damage, and construction defects. The exemption of these pipelines from the safety requirements of the Federal Pipeline Safety Regulations failed to consider the present risks that now exist.
- Identifying MCA: For liquids, PHMSA’s final rule encourages pipeline operators to “make better use of all available data to understand pipeline safety threats.”

PHMSA MEGA RULE PART 3 “GAS GATHERING RULE”

- TIMELINE

November 15, 2021	Publication Date
May 16, 2022	Effective Date
November 16, 2022	Identification of Type C lines
March 31, 2023	2022 Annual Report Due with new classifications
May 16, 2023	Full compliance with 192.9

PHMSA MEGA RULE PART 2 “REPAIR RULE”

- OVERVIEW

Part 2 of the Mega Rule focuses on improving pipeline integrity management best practices. It **mandates** inspections, repair times and new required practices for onshore gas transmission pipelines.

PHMSA MEGA RULE PART 2 "REPAIR RULE"

KEY HIGHLIGHTS

- **Cathodic Protection:** Gas pipeline operators must have an external corrosion management plan in place to limit the effect of electrical interference through surveying and assessment. They must then make efforts to mitigate this corrosion in a comprehensive manner alongside other test results.
- **Close Interval Surveying & Assessment:** If any pipe to soil measurements indicate that cathodic protection is below appropriate levels, the pipeline operator must conduct close interval surveys approximately every five feet in the affected area and remediate any issues within 12 calendar months.
- **AC Interference Monitoring:** Previously pipeline operators had to "consider" a recurring or continuous AC interference program to control and monitor accelerated corrosion due to power lines. Part Two now solidifies this request for "consideration" into a true requirement with remediation completed within 15 calendar months of completing the interference survey.
- **Internal Corrosion:** Pipeline operators must establish a program to monitor and mitigate internal corrosion. If they find that the pipeline is actively transporting corrosive gas, they must check the affected areas at least twice annually using coupons or other methods.

PHMSA MEGA RULE PART 2 “REPAIR RULE”

- TIMELINE

August 24, 2022	Publication Date
May 24, 2023	Rule goes into effect **(14 DAYS)**
February 26, 2024	All available integrity threats integrated with threat identification
May 23, 2030	First round of indirect surveys must be completed on all onshore gas transmission pipe that is under CP in an HCA segment

THE MEAT OF THE MATTER

- And Why We Are Meeting here today

- DCVG / ACVG / CIS REQUIREMENTS
- INTERFERENCE CURRENTS

PHMSA MEGA RULE PART 2
CODE CHANGES

§ 192.319 Installation of pipe in a ditch.

(d) The operator must perform DCVG, ACVG or other technology that provides information on coating quality not later than 6 months after placing the pipeline in service

(f) An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBmV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months after the pipeline is placed in service, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

PHMSA MEGA RULE PART 2
CODE CHANGES

§ 192.465 External corrosion control: Monitoring and remediation.

(f) in areas of low protection, an operator must determine the extent of the area in accordance with appendix D to this part.
(1) Gas transmission pipeline operators must investigate and mitigate any non-systemic or location-specific causes.
(2) To address systemic causes, an operator must conduct INTERRUPTED CIS IN BOTH DIRECTIONS …..and must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (d) of this section…..

PHMSA MEGA RULE PART 2

CODE CHANGES (INTERFERENCE CURRENTS)

§ 192.473 External corrosion control: Interference currents.

c) For onshore gas transmission pipelines, the program required by paragraph (a) of this section **must include**:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a **significant increase in stray current**, or when **new** potential stray **current sources are introduced, such as** through co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from **additional generation, a voltage up-rating, additional lines, new or enlarged power substations, or new pipelines or other structures**;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public;

PHMSA MEGA RULE PART 2

CODE CHANGES (INTERFERENCE CURRENTS CONT'D)

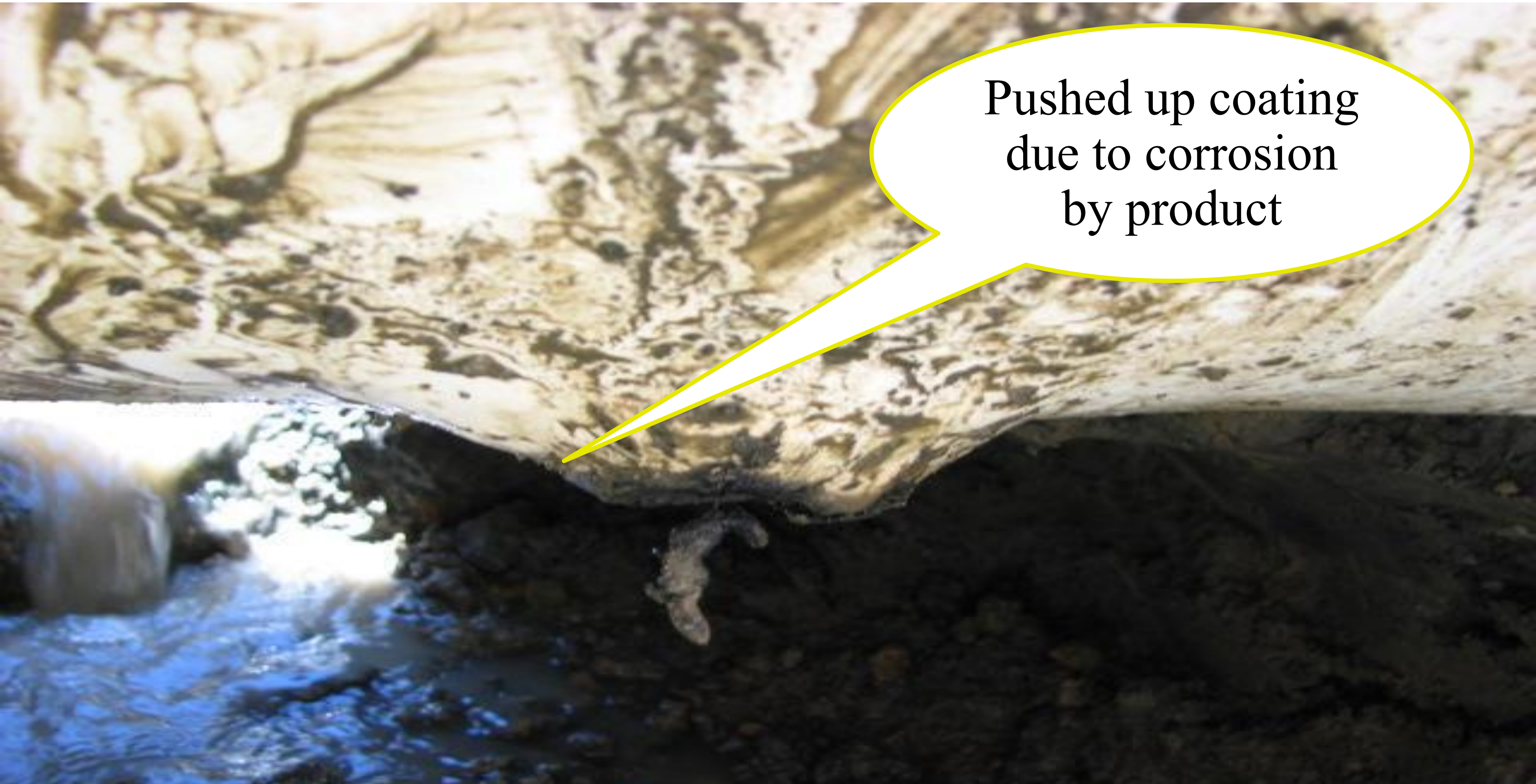
- (3) Development of a remedial action plan to correct any instances where interference current is greater than or equal to 100 amps per meter squared or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and
- (4) Application for any necessary permits within 6 months of completing the interference survey that identified he deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 6 months, after obtaining any necessary permits.

PHMSA MEGA RULE PART 2

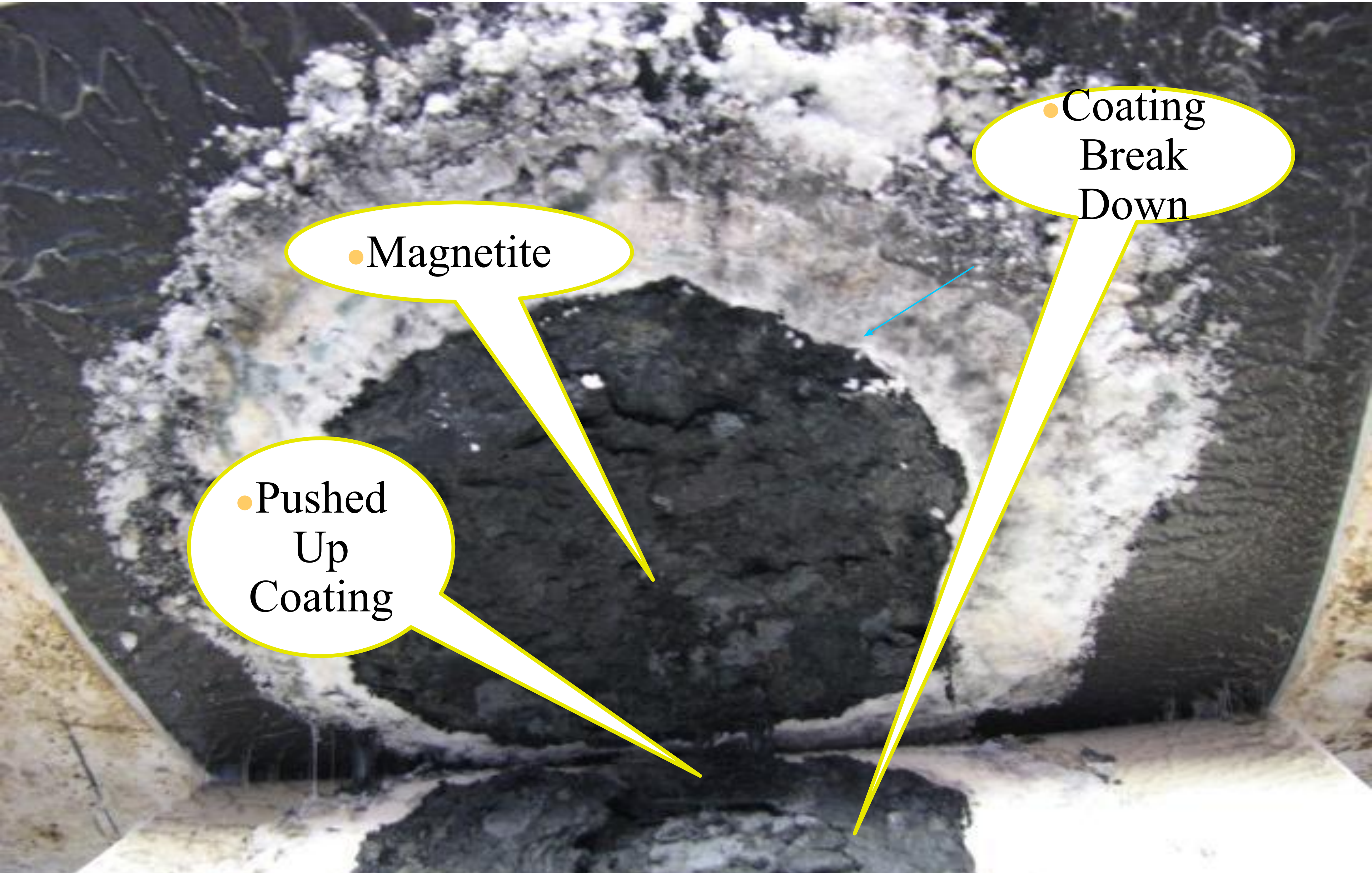
Supplemental Code Changes

- **§ 192.613 Continuing surveillance.**
- **§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking?**
- **§ 192.935 What additional preventive and mitigative measures must an operator take?**

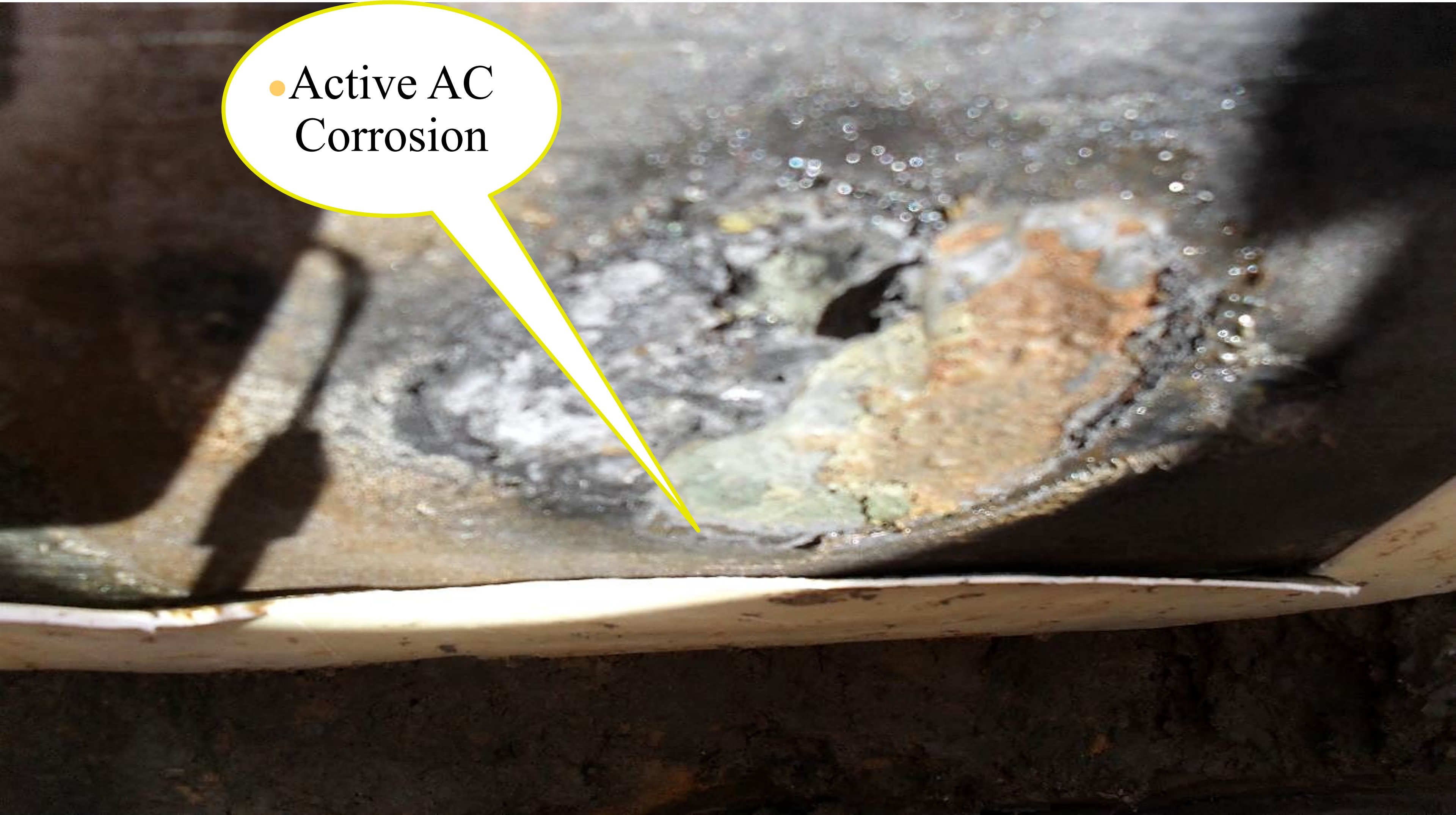
Signs of Coating Failure and AC Corrosion – Polyethylene Coating



AC Corrosion By Products

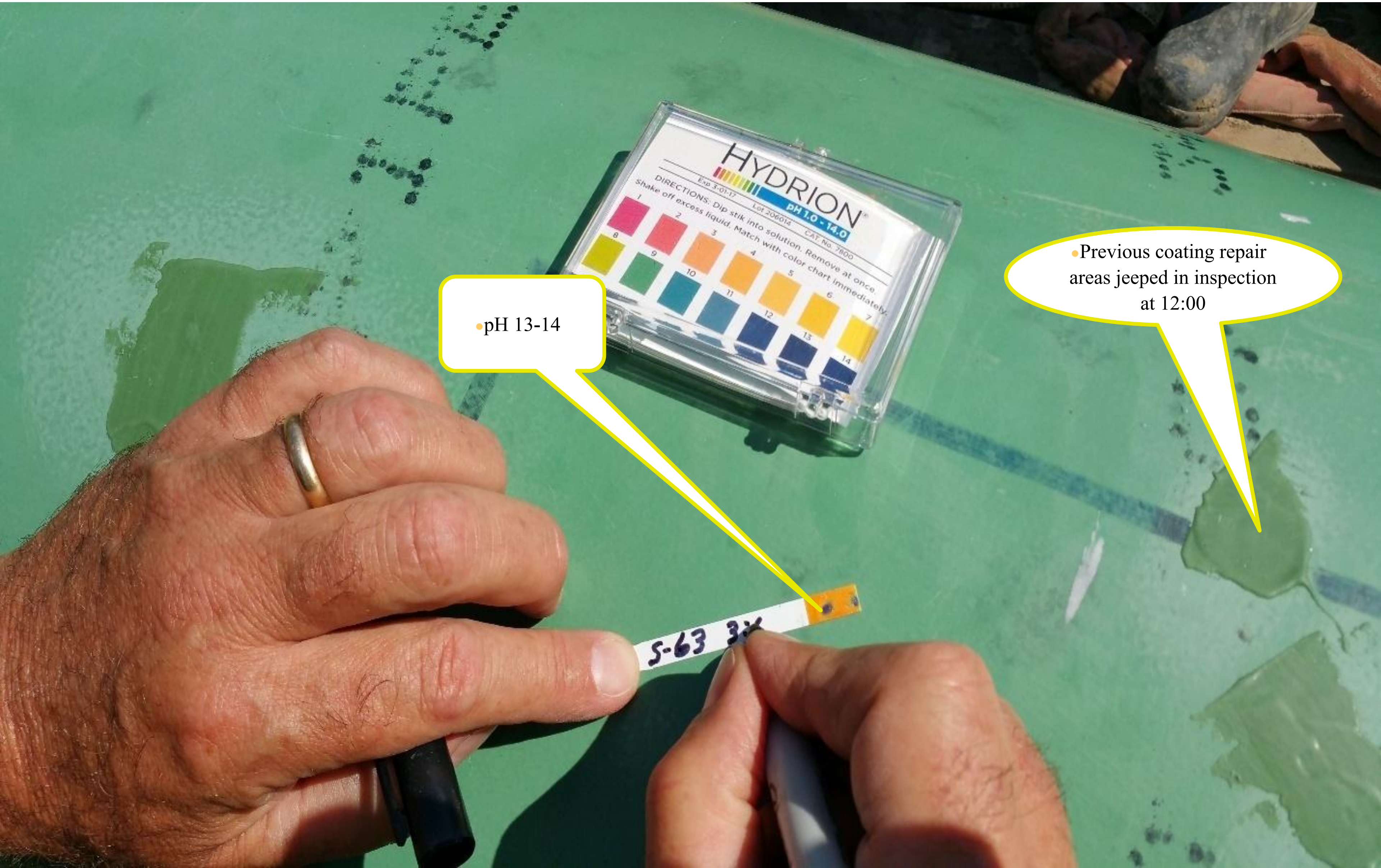


Circular Morphology



AC Corrosion

AC Corrosion - pH is Always 13-14



Thank You!

Any Questions?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