

Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Hydrocarbon Operations

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Foreword

This standard practice was prepared to encourage the use of uniform and industry-proven methods to monitor mass-loss and pitting corrosion in hydrocarbon operations.

Scope

This standard outlines procedures for preparing, installing, and analyzing metallic corrosion coupons. Factors considered in the interpretation of results obtained from these corrosion coupons are also included for the use of oil, gas and service industry personnel.

Rationale

In this revision, many lengthy paragraphs were modified technically, grammatically, broken into new paragraphs (with or without additional information) for better clarity, understanding and ease of reading (modifications include tables, equations and Appendix A [nonmandatory]). The major change to the standard is removal of the “Severe” category from the Qualitative Categorization of Carbon Steel Corrosion & Pitting Rates ([Table 2](#)), as “High” itself provides the undergoing corrosion risk for process streams.

Additionally, emphasis on photography of corrosion coupons is highlighted in this revision with the inclusion of new [Appendix B \(nonmandatory\)](#), showing coupons before/after cleaning, corrosion morphology, relevant data, findings and conclusion; to provide supplementary information and guidance for the user of this standard. Also, this revision highlights the importance of accessibility for servicing/retrieval of corrosion coupons or probes data collection and included access platform example photographs.

In AMPP standards, the terms *shall* and *must* are used to state requirements and are considered mandatory. The term *should* is used to state something that is recommended, but is not considered mandatory. The term *may* is used to state something considered optional.

Section 1: General

- 1.1** This standard is presented for the use of metallic corrosion coupons in hydrocarbon production and processing facilities, including but not limited to drilling, production, and transportation operations on land, onshore and offshore. Hydrocarbon operations handle fluids including but not limited to oil, water, gas, condensate, and drilling fluids.
- 1.2** This standard may be referenced by other industries that may process or handle corrosive fluids. However, subject matter experts familiar with corrosion mechanisms and corrosion monitoring in those industries shall be consulted for applicability, utilization and implementation of the recommendations of this standard.
- 1.3** When used in this standard, system denotes a functional unit including but not limited to: a producing well; flowline and tank battery; water, oil, or gas collection facility; water or gas injection facility; or a gas dehydration or sweetening unit.
- 1.4** Corrosion coupon testing consists of the exposure of a small specimen of metal (the coupon) to an environment of interest for a measured period of time to determine the reaction of the metal to the environment. Corrosion coupons are used to evaluate the corrosivity of various systems, to monitor the effectiveness of corrosion-mitigation programs, and to evaluate the suitability of different metals for specific systems and environments.
- 1.5** Coupons shall be installed in the system and exposed to the corrosive fluid in a manner that is as representative as possible; such that corrosion on the coupon may be considered indicative of corrosion within the system as a whole. Providing that coupons are exposed in the manner indicated, they may be inserted directly into a system or into a take-off or side stream from the main system.
- 1.6** General corrosion/pitting rates shown by coupons and most other corrosion-monitoring devices seldom duplicate the actual rates on the system piping, pipelines and vessels. Potentially more accurate system general

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corrosion/pitting rates may be determined by non-destructive measurement methods, such as manual ultrasonic (UT)/long range ultrasonic (LRUT) thickness measurements, or failure frequency curves. However, it must be understood that improvement in accuracy is dependent on locating the actual worst case general corrosion or pitting location.

- 1.7** High general corrosion/pitting rates on coupons may be used to verify the need for corrective action but should be considered with other monitoring and/or surveillance data. If a corrosion-mitigation program is initiated and subsequent coupon data indicate that general corrosion/pitting rates have been reduced based on the trend over time, i.e., a number of coupon sequential data points, the information can be used to approximate the effectiveness of the mitigation program. This standard does not contain information on monitoring for intergranular corrosion, stress corrosion cracking (SCC), or sulfide stress cracking (SSC). The latter aspects are discussed elsewhere.^{1,2}
- 1.8** This standard describes preparation and handling techniques for metal coupons prior to and following exposure. General corrosion/pitting rate calculations and a typical form for recording data are also included.
- 1.9** Coupon size, metal composition, surface condition, and coupon holders may vary according to the test system design or the user's requirements. Coupons are often installed in pairs for simultaneous removal and average general/pitting corrosion rate determination.
- 1.10** While pairs of coupons allow for determination of an average corrosion rate between the two individual coupons, the corrosion rate of each coupon is, by itself, an average of the corrosion that occurred over the exposure period. As such, corrosion coupons cannot accurately define occurrences of short duration, high corrosion rate periods; for example, process parameter or oxygen concentration excursions. As noted below; other online instrumentation providing more immediate and continuous specific parameter data may be required to identify short term, high corrosion rate excursions and identify their potential causal mechanism(s).
- 1.11** Coupons may be used alone, as a single corrosion measurement tool; however, they should be used in conjunction with other monitoring methods such as test nipples, hydrogen probes, galvanic probes, polarization instruments, resistance-type corrosion monitors, electro-chemical noise (ECN) methodologies/techniques, non-destructive metal thickness measurements, caliper surveys, corrosion failure records, and fluid, gas, deposit & bacterial proliferation analysis of process streams. The significance of ongoing, routine tracking of process stream composition cannot be overestimated, as it may not only be useful in the monitoring of corrosion rate fluctuations, but in the monitoring of overall process performance as well.
- 1.12** Corrosion coupons used as recommended in this standard measure general corrosion/pitting rates during the exposure period; showing corrosion that has already occurred. A single coupon cannot be used to determine whether the rate of corrosion/pitting was uniform or varying for single exposure period. However, a single coupon can provide proper information based on trending for prolonged periods and understanding of historical corrosivity behavior for specific process stream; provided that the process stream composition and fluctuations have been similarly tracked historically.
- 1.13** Additionally, information on the change in general corrosion/pitting rate can be obtained by installing several coupons at one time and removing/evaluating individual coupons at specific short-term intervals. Other monitoring methods stated in Paragraph 1.11 can be used to provide more accurate information on short-term rates of corrosion. Data provided by corrosion coupons can provide excellent backup for "event-indicating" corrosion-monitoring instruments.
- 1.14** In addition to general corrosion/pitting rates, important factors to consider in the analysis and interpretation of coupon data include location, both physical and orientation within the system, time on stream, measured pit depth, surface profile, visual observations (such as blistering, erosion, cracks, etc.), corrosion product and/or scale composition, microbiological activities, process stream compositional variation, and operational variation, e.g., downtime, system flow velocities, upsets, chemical inhibitor dosing excursions or changes (examples of deposits and corrosion damages on coupons can be seen in [Appendix B](#)).
- 1.15** Coupon general corrosion/pitting rates in one system shall not be compared directly with those in unrelated systems. However, general corrosion/pitting rates in similar systems (e.g., two systems handling identical environments/flow rates) can be used for correlation.

- 1.16** Additional information can be obtained within a system which has multiple coupon monitoring locations by varying exposure parameters at select locations. Possible examples might include extending or reducing exposure duration to monitor impact on corrosion product formation or corrosion rate, alternating coupon installation location within the system to determine if fluid velocities impact corrosion rates or if corrosion rates vary upstream or downstream of stream tie in points or where fluid compositions vary due to process fluctuations.

Section 2: Processing of Corrosion Coupons

2.1 Coupon Preparation

The metallurgical characteristics of the material utilized for the preparation of coupons for exposure in any given system shall, as closely as possible, mimic the characteristics of the metal in use in the system to be monitored.

Coupons placed in any system shall be new; do not re-use coupons after exposure and analysis. This restriction applies to systems with active corrosion monitoring.

The following procedure should be used to prepare coupons:

- 2.1.1** Choose a method of coupon preparation that does not alter the metallurgical properties of the metal. Grinding operations must be controlled to avoid high surface tensions/temperatures that could change the microstructure of the coupon.
- 2.1.2** A permanent serial number shall be etched or stamped on each coupon. It is possible for a coupon or holder to undergo SCC if the conditions in Paragraphs 2.1.2.1 and 2.1.2.2 are met:
- 2.1.2.1** Exposure to an environment capable of cracking the alloy used for the coupon or holder.
 - 2.1.2.2** Stress sufficiently high to cause cracking. Such stress can result from a combination of residual stress (such as introduced by stamping) and applied stress.
 - 2.1.2.3** Instances of SCC of carbon steel coupons under oil & gas field conditions have rarely been reported. Nevertheless, broken pieces of coupons or holders can lodge downstream in valves and interfere with their normal operation.
- 2.1.3** Machine or polish the edges of the coupon to remove cold-worked metal if the cold-worked edges adversely affect the data.
- 2.1.4** Coupons formed by stamping are preferred over machined coupons, as stringent quality control measures are followed during manufacturing. However, if a corporate decision is made to utilize in-house machined coupons, a defined quality control procedure shall be implemented, taking into consideration coupon metallurgy, dimensions, surface profile, weight, testing, packing and unique numbering or stamping for individual coupons.
- 2.1.5** Stamped coupons are satisfactory without additional machining for most oil and gas field monitoring.
- 2.1.6** Match the surface finish of the coupons with the finish of the metal being investigated, i.e., the pipe or vessel wall. Since this is seldom practical, other surface finishes are applied. No specific surface finish is absolutely essential, but the finish should have uniformity when data from different sets of coupons are being compared.
- 2.1.7** Coupons may be prepared by smooth grinding with 120 grit paper, by tumbling with loose grit, or blasting with abrasive blasting material. A consistent finish may be obtained by blasting with glass beads, but glass beads may not remove mill scale or rust. All abrasives should be free of metallic particles.

- 2.1.8** After the coupons have been cleaned, handle them by suitable means to prevent contamination of the surface with oils, body salts, and other foreign materials. Clean, lint-free cotton gloves or cloths, disposable plastic gloves, coated tongs, or coated tweezers should normally be used.
- 2.1.9** Under a ventilated hood, remove any residual oils with a naphthenic /paraffinic solvent (such as cyclohexane). If residual oils are not present, cleaning and rinsing with anhydrous isopropyl alcohol should be sufficient.
- 2.1.10** Dry, measure, and weigh the coupons to within ± 0.5 mg. Record the mass, serial number, and exposed dimensions. Calculate the surface area (including the edges) and record. The areas covered by the coupon holder and shielded areas of flush-mounted coupons must be excluded. (For test nipples or other large corrosion test pieces, see [Paragraph 3.6](#)).
- 2.1.11** Prior to shipment, store the individually packaged coupons in a closed container with indicating silica gel.⁽¹⁾ Coupons may be wrapped in paper or placed in envelopes impregnated with a vapor-phase corrosion inhibitor.

2.2 Procedure for Field Handling of Coupons Before Exposure

- 2.2.1** Prior to coupon installation, record the following information:
- Coupon serial number
 - Installation date
 - Name of system
 - Location of the coupon in the system (including fluid or vapor phase)
 - Orientation of the coupon and holder

A typical corrosion coupon report is shown in [Appendix A](#).

- 2.2.2** During installation, handle the coupon carefully to prevent contamination of the coupon surface. (See Paragraph 2.1.9).
- 2.2.3** When the coupon is removed, record the following:
- Coupon serial number
 - Removal date
 - Visual observations (damages, unusual coloring, erosion, velocity effects, etc.)
 - Appearance of adherent deposits (scale, corrosion product, hydrocarbons, etc.)
 - All other pertinent data (shut-in time, changes in flow, velocity, inhibitor treatment on/off and process modifications, if any)
- 2.2.4** The coupons should be photographed immediately after removal, particularly for the appearance of the adherent deposits or prevalent damages (See [Appendix B](#) for photographs of adherent deposits and different prevalent damages on coupons).
- 2.2.5** Additionally, adherent deposits should be collected immediately at site after retrieving the corrosion coupons and transferred to special moisture and air sealed plastic bottles or containers or bags to hand over to the laboratory to carry out chemical, bacterial proliferation, and X-ray Diffraction Analysis (XRD). For bacterial enumeration, use of a transportation medium may be required and must be pre-prepared and taken to the site for use immediately following coupon extraction.
- 2.2.6** For bacterial proliferation analysis utilizing the Most Probable Number (MPN) serial dilution technique (in accordance with NACE standards TM0194 and TM0106), adherent deposits collected from the removed coupons should be put into the culturing media immediately at site.

⁽¹⁾ Silica gel that has become inactive as a result of moisture absorption can be reactivated by heating in an open metal pan in an oven at 119 to 127 °C (246 to 261 °F) for at least 12 h. Reactivated silica gel must be stored in an airtight container. Indicating silica gel impregnated with cobaltous chloride changes color when it becomes saturated with moisture.

- 2.2.7** Protect the coupon from contamination by oxidation and handling. Place the coupon in a special envelope impregnated with volatile corrosion inhibitor (VCI), then place the envelope in a moisture-proof, air-tight container along with a fresh pack of desiccant and ship immediately to a laboratory for analysis. Do not coat the coupon with grease or otherwise alter it. Gentle blotting with tissue paper or a clean soft cloth may be done to remove excess moisture prior to shipment.

2.3 Laboratory Procedure for Cleaning and Weighing Coupons After Exposure

- 2.3.1** Record the coupon serial number. If the coupon was not photographed in the field, it should be photographed in the laboratory before and after cleaning (see Appendix B for photograph examples). Prior to any cleaning, weigh the coupon to within ± 0.5 mg in a calibrated analytical balance.
- 2.3.2** Visually examine the coupon and record observations. Compare the pre-cleaning observations with field extraction records and or photographs.
- 2.3.3** Qualitative/Quantitative analysis (wet chemistry, sulfide materials presence via H_2S evolution, carbonate scales via CO_2 evolution, Cl^- concentration, XRD, bacterial analysis, etc.) of adherent deposits should be performed.
- 2.3.4** Under a ventilated hood, immerse the coupon in a suitable naphthenic /paraffinic solvent (such as cyclohexane) long enough to remove the oil, oil-wet materials, and paraffin. Rinse with anhydrous isopropyl alcohol (mentioned in [Paragraph 2.1.9](#)). Dry in a gentle dry air stream and weigh the coupon to within ± 0.5 mg if quantitative analysis of acid-soluble deposits is desired.
- 2.3.5** Immerse steel coupons in 15% inhibited hydrochloric acid to remove mineral scale and corrosion products. Ultrasonic agitation may be used to accelerate the cleaning process. Numerous commercial inhibitors are available to protect the steel during acid cleaning. The following inhibitor solution has been successful: A stock solution is made of 37.5% HCl to which 10 g/L of 1,3-di-n-butyl-2 thiourea (DBT) has been added.³ Immediately prior to use, the stock solution is diluted by slowly adding a measured volume of stock solution to an equal volume of distilled water with stirring. Additional information on cleaning metals other than steel should be consulted.⁴⁻⁷
- 2.3.6** After cleaning, immerse the coupon in a saturated solution of sodium bicarbonate for one minute to neutralize the acid. Rinse with distilled water to remove the neutralizer. Rinse the coupon immediately in isopropyl alcohol or acetone and dry in a stream of dry air. Air-lines should be equipped with traps and filters to remove all oil and water. Coupons with tenacious films should be scrubbed with a household cleanser and 000 steel wool prior to drying with alcohol or acetone. Visually examine the coupon and record observations.
- 2.3.7** Coupons with tightly adherent deposits should be cleaned by blasting with glass beads. Mass loss during blast cleaning should be determined by cleaning unexposed coupons in accordance with Paragraph 2.3.8.
- 2.3.8** Subject a pre-weighed blank coupon (not exposed to the corrodent) to the cleaning process to ensure that mass loss from cleaning is not significant.

2.4 Calculation of the Average General Corrosion Rate (CR)

The following procedures should be used to calculate the average corrosion rate:

- 2.4.1** Determine the mass loss of the corrosion coupon and divide the mass loss by the product of the metal density ([Table 1](#)), the total exposed surface area, and the exposure time to obtain the average rate of corrosion.

The following equations should be used to determine the average corrosion rate depending on the units desired.⁶

- 2.4.1.1** Calculation of average general corrosion rate, expressed as a uniform rate of thickness loss per unit time in millimeters per year (mm/y), is shown in Equation (1):

$$CR = \frac{W \times 365 \times 1,000}{ATD} = \frac{3.65 \times 10^5 \times W}{ATD} \quad (1)$$

where:

CR = average corrosion rate, millimeters per year (mm/y)
W = mass loss, grams (g)
A = initial exposed surface area of coupon, square millimeters (mm²)
T = exposure time, days (d)
D = density of coupon metal, grams per cubic centimeter (g/cm³)

- 2.4.1.2** Calculation of average general corrosion rate, expressed as uniform rate of thickness loss per unit time in mils per year (mpy), is shown in Equation (2):

$$CR = \frac{W \times 365 \times 1,000}{ATD \times (2.54)^3} = \frac{2.227 \times 10^4 \times W}{ATD} \quad (2)$$

where:

CR = average corrosion rate, mils per year (mpy)
W = mass loss, grams (g)
A = initial exposed surface area of coupon, square inches (in²)
T = exposure time, days (d)
D = density of coupon metal, grams per cubic centimeter (g/cm³)

- 2.4.1.3** Calculation of the average general corrosion rate, expressed as a uniform rate of mass loss per unit area per unit time in grams per square meter per day (g/m²/d), is shown in Equation (3):

$$CR = \frac{W}{A \times T} \quad (3)$$

where:

CR = average corrosion rate, grams per square meter per day (g/m²/d)
W = mass loss, grams (g)
A = initial exposed area of coupon, square meters (m²)
T = exposure time, days (d)

- 2.4.1.4** Calculation of average general corrosion rate, expressed as a uniform rate of mass loss per unit area per unit time in pounds per square foot per year (lb/ft²/y), is shown in Equation (4):

$$CR = \frac{W \times 365 \times 144}{AT \times 453.6} = \frac{W \times 1.159 \times 10^2}{AT} \quad (4)$$

where:

CR = average corrosion rate, pounds per square foot per year (lb/ft²/y)

W = mass loss, grams (g)

A = initial exposed area of coupon, square inches (in²)

T = exposure time, days (d)

Table 1
Density of Metals^(A)

Material	Density, g/cm ³	Material	Density, g/cm ³
Cast Irons		Copper Alloys	
Gray cast iron	7.15	Admiralty brass	8.53
Malleable iron	7.27	Red brass, 85%	8.75
Steels		Yellow brass	8.47
		Bronze--5% Aluminum	8.17
Carbon steel	7.86	Bronze-Phosphor 10%	8.78
Low-alloy steels	7.85	Copper-Nickel (90-10)	8.84
9 Cr-1 Mo	7.67	Cast Al-Bronze	7.80
5 Ni	7.98	Beryllium Copper	8.35
9 Ni	8.10	Other Materials	
Stainless Steels		Aluminum (Al)	2.70
UNS ^(B) S30400 (Type 304)	7.90	Magnesium (Mg)	1.74
UNS S31600 (Type 316)	8.00	Nickel (Ni)	8.90
UNS S32100, S34700 (Types 321, 347)	8.02	Zinc (Zn)	7.13
UNS S41000 (Type 410)	7.70		
13 Cr	7.70		
17-4 PH	7.80		
22 Cr-5 Ni (duplex)	7.89		

^(A) Alloys are wrought unless otherwise noted. (Source: *ASM Handbook*, Vol. 1, Properties and Selection: Irons, Steels, and High-Performance Alloys, 10th ed., 1990, ASM International).

^(B) *Metals and Alloys in the Unified Numbering System* (latest revision), a joint publication of ASTM International (ASTM) and the Society of Automotive Engineers Inc. (SAE).

2.4.1.5 Conversion Factors:⁸⁻¹⁰

1 mm/y = 39.4 mpy

1 μm/y = 0.0394 mpy (μm = micrometer)

1 mpy = 0.0254 mm/y

1 mpy = 0.001 in/y (inches per year)

1 mil = 0.001 in

2.5 Calculation of the Maximum Pitting Rate (PR)

The following procedure should be used to calculate the maximum pitting rate:

- 2.5.1** Determine the depth of the deepest pit and divide by the exposure time. The following Equations (5) and (6) may be used to determine the maximum pitting rate depending on the units desired.

$$PR \text{ (mm/y)} = \frac{\text{depth of deepest pit (mm)} \times 365}{\text{exposure time (days)}} \quad (5)$$

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$$PR \text{ (mpy)} = \frac{\text{depth of deepest pit (mil)} \times 365}{\text{exposure time (days)}} \quad (6)$$

- 2.5.2** Pit depths may be measured with a depth gauge or a micrometer caliper with needlepoint anvils. The anvil must be small enough to reach the bottoms of the pits.
- 2.5.3** An optical microscope calibrated for depth measurement may also be used to estimate pit depth. The microscope should be focused first on uncorroded metal adjacent to the pit and then focused on the bottom of the pit.
- 2.5.4** Metallographic cross sections through pits provide an accurate measurement of pit depth if a high degree of accuracy is deemed necessary. The same measurement technique should be used on all coupons from a given system.
- 2.5.5** Pit density per unit area should be reported.
- 2.5.6** Additional information on the measurement of pits can be found in ASTM⁽²⁾ G46.¹¹
- 2.5.7** Pitting characterization by calculation of pitting rate may be misleading if pitting onset occurs after an incubation period. Time to pitting onset varies and pit growth may not be uniform. Therefore, other inspection methods (discussed in [Paragraph 1.6](#)) should be exercised in applying calculated pitting rates to project time-to-failure.

Section 3: Corrosion Coupons (Type, Size, Composition, Material, and Installation)

3.1 Types of Corrosion Coupons

- 3.1.1** Corrosion coupons are available from various suppliers or can be fabricated in-house (discussed in [Paragraph 2.1.4](#)).
- 3.1.2** Coupons are available in many different sizes and configurations. The size and configuration selected depend on the type of holder being used, line size, and entry orientation.
- 3.1.3** Special access fittings and devices that allow installation and retrieval under pressure may require a specific type of coupon. It is usually advantageous to standardize a few sizes to minimize inventories and to eliminate difficulties in preparation and handling.
- 3.1.4** Circular (washer-type) coupons shown in [Figure 1](#) are available in various sizes. The size of the circular coupon, which fits between a pair of ring joint flanges, depends on the size and type of flange in which the circular coupon is to be installed.

⁽²⁾ ASTM International (ASTM), 100 Barr Harbor Dr., West Conshohocken, PA 19428-2959, www.astm.org.

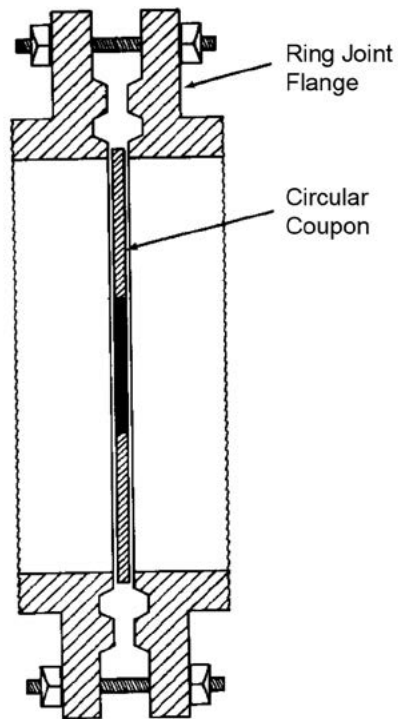


Figure 1: Circular (Washer Type) Coupon and Typical Mounting in a Ring Joint Flange

- 3.1.5** Ring-type coupons for use in drill pipe tool joints are shown in [Figure 2](#). Additional information on the use of drill pipe coupons can be found in API⁽³⁾ RP 13B-1.¹²

⁽³⁾ American Petroleum Institute (API), 1220 L St. NW, Washington, DC 20005, www.api.org.

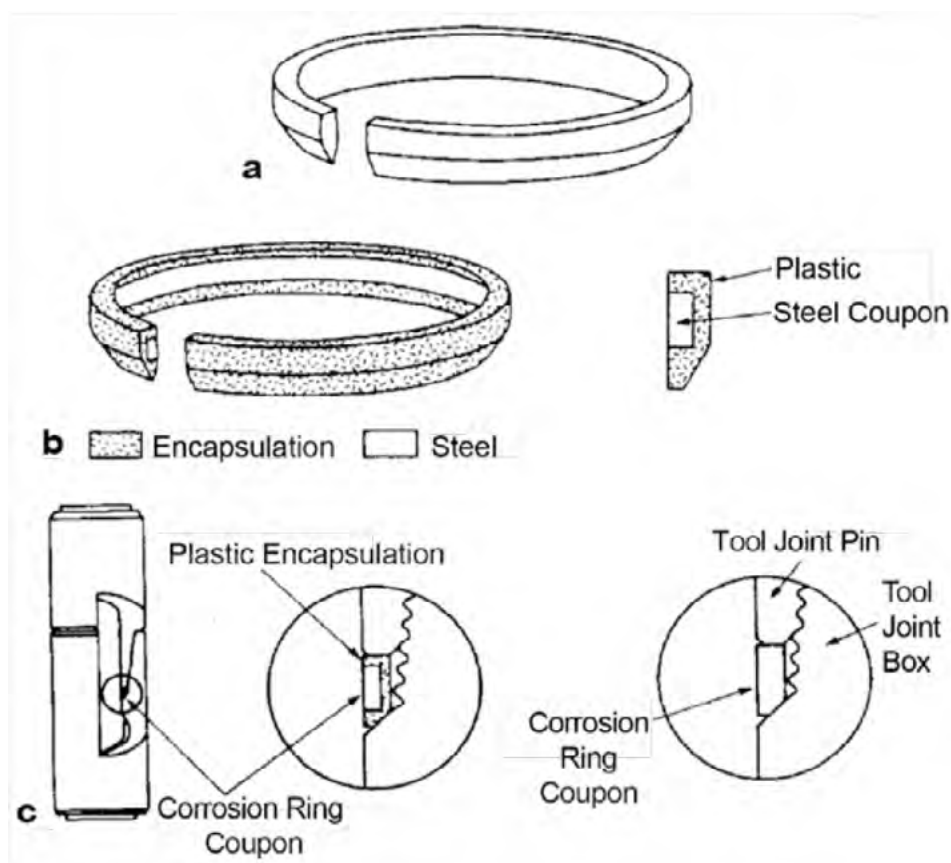


Figure 2: Drill Pipe Corrosion Ring Coupon: (a) Steel Corrosion Ring (Fabricated in Accordance with API RP 13B-1); (b) Steel Corrosion Ring Coupon Encapsulated in Plastic; and (c) Installed

3.1.6 Corrosion coupons can be modified for studies of oxygen concentration cells. A rubber band can be placed around the coupon, excluding oxygen from the metal under the rubber band.¹³

3.1.7 An oil-resistant elastomer should be used if hydrocarbons are present.

3.1.8 Banded coupons should not be used for mass-loss determinations. Coupons banded in this manner are not practical in high-velocity streams.

3.2 Coupon Composition

3.2.1 Coupons are usually made of 0.1 to 0.2% carbon steel that is readily available in strip and plate form and is easily worked.

3.2.2 Depending on the reason for testing, metals used should normally be identical to those in the system, but may also include metals and alloys that are being considered for use in the system.

3.3 Coupon Holders

3.3.1 Coupon holders are available in many sizes and shapes to hold one or more flat or round (rod-type) coupons. Some common coupon holders are shown in [Figures 3](#) and [4](#).

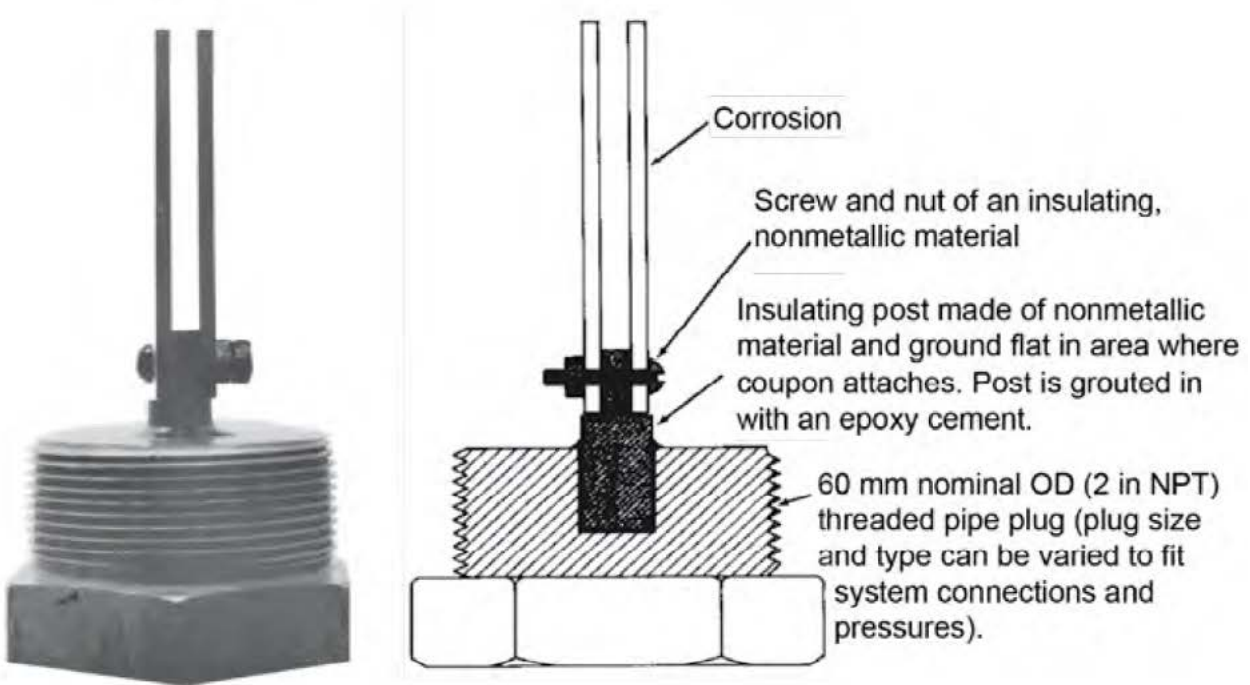


Figure 3: Flat Coupon Holder Using a 60 mm Nominal OD (2 in NPT) Threaded Pipe Plug. Also Shows Insulation Method and Attachment of Corrosion Coupon

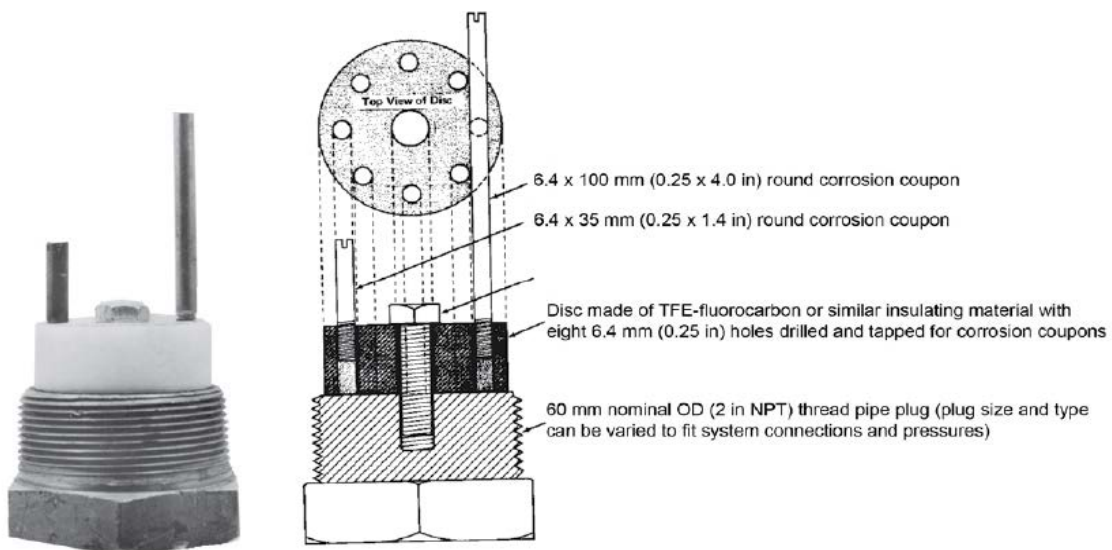


Figure 4: Round (Rod-Type) Coupon Holder Using a 60 mm Nominal OD (2 in NPT) Threaded Pipe Plug

3.3.2 Depending on the system, corrosion coupons may be mounted in a variety of ways. Mounting must accomplish the following:

- 3.3.2.1** Adequate support of the coupons in the system.
- 3.3.2.2** Electrical isolation of the coupon from other coupons, from the coupon holder, and from the pipe or vessel wall, to prevent galvanic corrosion.
- 3.3.2.3** Maintenance of the coupon's position in the desired location and positioning it in the system (i.e., either in the fluid or vapor phase, perpendicular or parallel to the flow stream).
- 3.3.2.4** Provision for easy and rapid changing of coupons in the field.
- 3.3.3** Coupon holders like the one shown in [Figure 3](#) should be marked externally on the solid plug hex so the coupon orientation can be determined when it is in service. An orientation parallel to the process flow for strip coupons should be used, as it reflects the true condition experienced by process streams (See [Paragraph 3.4.13](#)).
- 3.3.4** Coupon holder length should be determined (based on pipe wall thickness, diameter, access and fitting length) as per the applicable equations.
- 3.3.5** The system must be depressurized prior to installation and removal of the coupons and coupon holders shown in [Figures 3](#) and [4](#).
- 3.3.6** Two examples of special-purpose coupon holders that provide for installation and removal of the coupon from a pressurized system are shown in Figures 5 (low and intermediate pressure) and Figure 6 (low, intermediate, and high pressure). An installation tool that can be used with conventional valves is shown in Figure 5. An installation assembly that requires a special fitting on a line or vessel is shown in [Figure 6](#). When installation and removal of coupons from a pressurized system is considered, the system design must accommodate the tool length. Overall length depends on the distance from the access valve to the final insertion depth in the pipe or vessel.



Figure 5: Tool for Installing and Removing Coupons in Systems under Pressure. The Pipe Nipple Screws into an Existing Valve on the Line or Vessel. Complete Assembly is Shown on Left. After the Coupon has been Positioned, the Drive Unit is Removed and the Coupon Holder is Locked as Shown on the Right

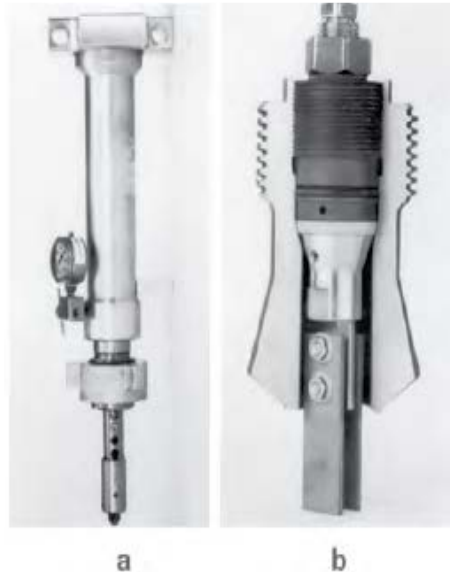


Figure 6: Extractor Tool for Inserting and Removing Coupons in Systems under Pressure: (a) Insertion Assembly used to Install Coupon Holder in Access Fitting. Insertion Assembly is Removed after Coupons are Placed in Access Fitting; and (b) Cutaway of Special Access Fitting used with Extractor Tool. Fitting is Welded to Line or Vessel. Shown with Coupon and Coupon Holder Installed

- 3.3.7** Coupon holders to secure a disk-type coupon flush with the pipe wall are available. Coupons flush with the pipe wall are subject to less turbulence than flat or round coupons that protrude into the flowing stream. Therefore, the flush-mounted coupons should provide information that is more representative of corrosion on the pipe wall.
- 3.3.8** The disk-type coupons should be held in place with either plastic or coated steel screws.
- 3.3.9** In some systems, iron sulfide deposits may bridge between the coupon and pipe wall, which can increase or decrease the rate of corrosion on the coupon.
- 3.3.10** Coupon holders for placing coupons in well tubing are also available. Coupons can be attached to a tubing stop (see Figure 7),¹⁴ which may be available from some subsurface pump suppliers and wire-line service companies. Another coupon holder that can be set by wire line in a side-pocket mandrel is available from gas lift equipment suppliers and wire-line service companies.

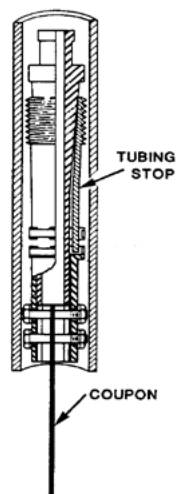


Figure 7: Wire-Line-Operated Tubing Stop Adapted as Downhole Coupon Holder

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3.4 Location in the System

- 3.4.1** To obtain the most reliable information from corrosion coupons, as well as from any other type of corrosion monitoring devices, coupons shall be located where corrosion is anticipated to occur or has been observed to have already occurred.
- 3.4.2** Coupons must be placed within and in direct contact with the corrosive phase.
- 3.4.3** Physical placement of coupons shall be such that system induced flow anomalies cannot affect the corrosion rates observed, and cannot influence flow due to appurtenances.
- 3.4.4** Corrosion, design, process and safety engineers shall collaborate to ensure that sufficient, properly located access fittings for corrosion monitoring are included in the design of new facilities.
- 3.4.5** In existing operating systems, corrosion failure records can help identify corrosive areas.
- 3.4.6** Ultrasonic and radiographic metal thickness measurements can be made to locate areas where corrosion has occurred.
- 3.4.7** Coupons can function in either the liquid or vapor phase of a system.
- 3.4.8** In new systems, experience with other similar systems is helpful.
- 3.4.9** Locations that should be considered for coupon installation should include, but are not limited to the following:
- Dead legs.
 - Low flow/velocity fluid or vapor streams.
 - High-velocity fluid streams and impingement points.
 - Downstream from points of possible oxygen entry, such as tanks, pumps, vapor recovery units, and water makeup lines in gas sweetening systems.
 - Locations where water is likely to collect.
 - In sour⁽⁴⁾ systems, such as suction scrubbers on compressors, separators, water drain lines from dehydrators, and low spots in wet gas lines.
 - Amine and glycol streams that contain sour gas.
 - Vapor sections in sour glycol regenerators.
 - Areas where a liquid and vapor interface occurs.
- Note:** Corrosion monitoring stations should be minimized in high pressure gas transmission pipelines due to the high risk of incidents that can take place in case of leakages occurring from corrosion monitoring access fittings. Leakages can occur due to several reasons, such as deteriorated rubber seals, improper set up, poor workmanship, severe corrosion on the access fitting, etc. In many cases, high pressure transmission gas pipelines are strategic pipelines for sales and export. Minor repairs for access fittings during leakages may require full purge of the pipeline, leading to extended stoppages.
- 3.4.10** In locations handling low pressure, water can accumulate at changes in the line elevation, as depicted in Figures 8A, 8B and 8C.
- 3.4.11** Corrosion may increase in depth and extent where water has accumulated. Coupons in such systems must be located at appropriate locations where they will be water-wet to correlate with corroding areas.

⁽⁴⁾ The term sour is used in this standard to denote systems containing hydrogen sulfide (H₂S).

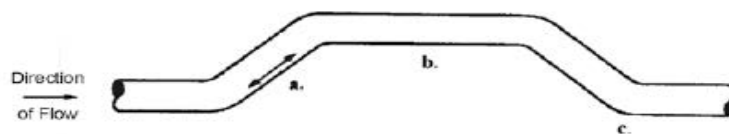


Figure 8A: With Low Flow Rate (Below Limiting Velocity)*

- a) Water oscillates—corrosion accelerated.
- b) Corrosion not accelerated.
- c) Water impinges at C—corrosion accelerated with higher flow rate (above limiting velocity). * Corrosion most severe at impingements.

*Limiting velocity—velocity above which erosion damage can be expected.

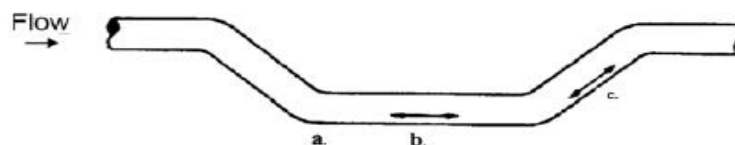
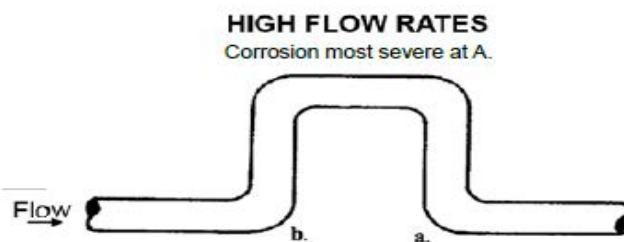


Figure 8B: Low Flow Rate

Corrosion most severe at B and C.



HIGH FLOW RATES

Corrosion most severe at A.

Figure 8C: Vertical Riser in Gas Line Carrying Small Volume of Water

- a) In high-velocity flow, water impinges on Points A and B, accelerating corrosion.
- b) At low velocity, water accumulates in upstream leg of loop, cascades down in downstream loop, impinging at Point A.

Figure 8A, 8B and 8C: Choice of Location for Coupon Installation and Interpretation of Coupon Corrosion Rate Measurements Must Take into Consideration Possible Fluid Build-Up Locations and Impingement Points. This Figure Shows what can Occur at Changes in Direction and Elevation in a Wet Gas System. Whether the Conditions Described Actively Exist Depends on Many Factors, Particularly Velocity

- 3.4.12** Corrosion on subsurface well equipment may be monitored by installing cleaned and weighed tubing subs, or pup joints (600 mm [2 ft] long) may be installed in the sucker-rod string as corrosion coupons. The tubing and rod subs should be located near the bottom, middle, and top of the well. The use of coupons in the sucker-rod string is usually unnecessary because each rod in the string acts as a coupon.
- 3.4.13** Corrosion of wellhead fittings on high-velocity flowing wells that produce organic acids, carbon dioxide, and water may be very severe. Corrosion coupons should be located both upstream and downstream from chokes to evaluate the effects of changes in velocity, temperature, phase, and the impact of solid particulates creating accelerated erosion corrosion.
- 3.4.14** Coupons located in flow lines of wells may be affected by paraffin or asphaltene accumulation. Coupons should be located in a section of the line that is free of paraffin or asphaltene deposits.

- 3.4.15** Coupons located in surface lines from wells may not provide accurate information on downhole corrosion rates. However, trends can usually be identified.
- 3.4.16** In horizontal multiphase flow, phases can sometimes be stratified. Care must be taken to ensure the coupon is exposed to the corrosive phase(s). For example, in low pressure wet gas system, flush disk-type coupons can be placed in annular flow sections of the pipe to ensure contact with the water phase.

3.5 Exposure Time

- 3.5.1** Exposure time must be considered when interpreting corrosion coupon data. Short-term exposure (15 to 45 days) provides quick answers but may give higher corrosion rates than long-term exposures. Aggravating conditions, such as bacterial fouling, may take time to develop on the coupon. Short exposure times may be advantageous when evaluating inhibitor effectiveness.
- 3.5.2** Longer exposures (60 to 90 days) are often required to detect and define pitting attack. Multiple coupon holders can be used so that both the short- and long-term effects can be evaluated. Since exposure time affects test results, exposure periods should be as consistent as practical. A tolerance of $\pm 7\%$ allows a variation of ± 2 d on a 30 d exposure. This is satisfactory for most applications.
- 3.5.3** When coupons are used to evaluate and monitor corrosion-inhibitor treatment, new coupons must be installed just prior to treatment. This is particularly important when there is a long period between treatments (as in inhibitor squeeze, tubing displacement, and infrequent batch treatment of gas wells).

3.6 Other Monitoring Devices

3.6.1 Test Nipples/Spools

- 3.6.1.1** These are normally short (300 to 900 mm [1 to 3 ft]) lengths of tubular goods of the same size and metal composition as the material used in the system. If test nipples are made from the same material as adjacent piping, galvanic corrosion of the test nipple is not a problem and insulating the nipples from the pipe should not be necessary. If the compositions of test nipples and piping are different, electrical isolation should be used to prevent galvanic corrosion. Electrical isolation of test nipples in lines operating above 14 MPa (2,000 psi) and 93 °C (200 °F) is practical only if flanged spools are used for test nipples.
- 3.6.1.2** Test nipples are usually exposed for longer periods (90 days to two years) than coupons. Shorter exposure periods can provide some information, but accurate general corrosion/ pitting rate determinations may require exposure of six months or more.
- 3.6.1.3** Test nipples shall be cleaned and accurately weighed prior to and after exposure to allow calculation of general corrosion/ pitting rates during the exposure period.
- 3.6.1.4** Mass loss/general corrosion rate may also be determined by accurate measurement of the internal volume of the test nipple before exposure and again after exposure and cleaning. To measure pit depths, nipples can be split longitudinally after mass loss is determined.
- 3.6.1.5** The external surface of the test nipple should be protected from atmospheric or soil corrosion if the mass loss is to reflect only internal corrosion. The addition of heavy flanges to a corrosion nipple may prevent accurate direct mass-loss measurements. However, flanged nipples can provide useful data on pitting rates.

3.6.2 Electronic Devices¹⁵⁻¹⁷

Electronic corrosion and inhibitor film monitoring instruments include electrical resistance measuring instruments, polarization instruments, galvanic probes, and electrolytic and vacuum-type hydrogen probes. All of these instruments are useful in detecting short-term upsets that may not be detected by coupons, which measure average corrosion rates. Some of the polarization and galvanic probes have removable metal elements that can be weighed before and after exposure.

3.6.3 Hydrogen Probes

Corrosion coupons may be attached to the ends of pressure-type hydrogen probes to compare coupon mass loss to the amount of hydrogen collected in the hydrogen probe. The coupon is isolated electrically from the body of the hydrogen probe.¹⁸

3.6.4 Additional Methods for Monitoring Corrosion

Additional monitoring methods that can be used in conjunction with coupons are listed in [Paragraph 1.11](#).

Section 4: Recording Data on Corrosion Coupon Report

- 4.1** The typical corrosion coupon report form in [Appendix A](#) shows the type of information that should be reported in a corrosion monitoring program. A separate form should be used for each coupon. Similar coupon report forms are available from commercial laboratories and inhibitor suppliers. Complete records of coupon testing are very important in evaluating corrosion mitigation programs.

Section 5: Interpretation of Corrosion Coupon Data

5.1 Corrosion Rate Interpretations

- 5.1.1** Qualitative guidelines for interpretation of measured corrosion and pitting rates are given in [Table 2](#).
- 5.1.2** The average corrosion and pitting rates shown in Table 2 are intended for use only as guides.
- 5.1.3** The table was compiled from information for carbon steel systems.
- 5.1.4** Common sense must be exercised in the evaluation of general corrosion/pitting rates as shown by corrosion coupons.
- 5.1.5** Coupons installed in dynamic systems can indicate a higher general corrosion/pitting rates than is actually occurring on the interior wall of the system piping.
- 5.1.6** Conventional coupons protrude into the flow stream and thus are subjected to more turbulence than the pipe wall.
- 5.1.7** Coupons are initially clean and free of protective films that may be providing considerable protection to the pipe wall. The general corrosion/pitting rates of a coupon can be much greater during the first days than after an exposure of one month. After the coupon has been exposed to the environment, protective films such as oil, carbonates, iron oxides, and sulfides may begin to form on the coupon and slow the general corrosion/pitting rates.
- 5.1.8** In other systems, general corrosion/pitting rates can increase with longer exposure time.
- 5.1.9** Pitting sometimes begins only after an “incubation period.”

- 5.1.10** Under deposit corrosion usually becomes severe only after the coupon is exposed long enough for deposits to form.
- 5.1.11** A coupon made of a corrosion-resistant metal may be exposed adjacent to the coupon under test to assess the effects of mechanical erosion.
- 5.1.12** Use of guidelines in [Table 2](#) must be tempered by asset's design life, economic considerations and safety requirements. For example, a short-lived project can normally tolerate a higher corrosion rate than a long-term/high-investment project.
- 5.1.13** The average corrosion rate calculation ([Paragraph 2.4.1](#)) assumes a uniform loss of metal, which is usually not the case in production operations. These data must be tempered by the maximum pitting rate ([Paragraph 2.5](#)) to determine the severity of the corrosion from an operation standpoint. Example: A pitting rate of 0.13 mm/y (5.0 mpy) on a thin-walled heat exchanger tube is serious. The same rate of pitting on a 76 mm (3.0 in) thick casting is normally inconsequential. Pitting rates should be evaluated in light of the considerations outlined in Paragraph 2.5.

5.2 System Corrosivity Interpretations

- 5.2.1** Data gathered from the use of corrosion coupons may be used to indicate the relative corrosiveness of a system.
- 5.2.2** The classifications of "Average General Corrosion/Pitting Rates" used in Table 2 may also be interpreted as the relative corrosiveness of a system as Low, Moderate and High.
- 5.2.3** It should be understood that the accuracy of the interpretation of corrosion coupon data as system corrosiveness is subject to many of the same limitations listed in [Paragraphs 5.1](#) and 5.3. However, system corrosiveness interpretations can be used to evaluate corrosiveness of systems, to monitor the effectiveness of corrosion mitigation programs, and to evaluate the suitability of different metals for specific systems and environments.
- 5.2.4** System corrosivity assessments are more robust when multiple corrosion measurement devices and multiple corrosion detection methodologies are utilized.

5.3 Interpretation Limitations

- 5.3.1** Factors that can contribute to the lack of correlation between general corrosion/pitting rates trends for coupons and process streams corrosivity include coupon location, multiphase flow characteristics and sudden/unknown changes in operating conditions such as flow, velocity, process flow changes, introduction/deletion of process stream and chemical injection dosage changes.
- 5.3.2** Coupons installed in a single-phase system, such as a water injection line, correlate with corrosion/pitting rates on system components better than coupons in three-phase systems of oil, water, and gas.
- 5.3.3** In stratified multiphase systems, attack may be confined to the part of the coupon exposed to the corrosive phase.
- 5.3.4** Coupons provide valuable information for long-term exposures such as type of anticipated corrosion damages, bacterial proliferation, deposition or any unusual observations.
- 5.3.5** Intermittent conditions which create excessively high instantaneous or short term corrosion rates, such as periodic entry of oxygen into a water system or water into a gas system, usually cannot be characterized by standard corrosion coupons with any degree of accuracy.
- 5.3.6** Banded coupons sometimes provide qualitative evidence of intermittent oxygen entry. Such intermittent conditions may be detected by recording polarization or galvanic instruments (liquid phase) or by resistance-type instruments that are read frequently (liquid or gas phase).

- 5.3.7** Coupon data reflect only the average general corrosion/pitting rates during the test period.
- 5.3.8** Major changes such as the initiation of an effective mitigation program may be evaluated with corrosion coupons.
- 5.3.9** Coupons are useful in providing back-up for other types of corrosion monitors.
- 5.3.10** Coupon data should also be correlated with the corrosion failure frequency in the system being assessed/studied.

Table 2
Qualitative Categorization of Carbon Steel Corrosion & Pitting Rates

Average General Corrosion Rate (See Paragraph 2.4)			Maximum Pitting Rate (See Paragraph 2.5)	
	mm/y ^(A)	mpy ^(B)	mm/y	mpy
Low 	< 0.05	< 2.0	< 0.13	< 5.0
Moderate 	0.05 – 0.2	2.0 – 8.0	0.13 – 0.3	5.0 – 12
High 	> 0.2	> 8.0	> 0.3	> 12
^(A) mm/y = millimeters per year ^(B) mpy = mils per year				

- Note:**
- (A) “Extremely High” term may be used for general corrosion and pitting rates that are 2x or higher than the values given in the “High” category above.
 - (B) Random physical inspections of piping or pipelines should be carried out whenever general corrosion and pitting rates are found in the higher end of the moderate category (i.e., 6 mpy to 8 mpy for general corrosion rates and 10 mpy to 12 mpy for pitting rates) for two or three consecutive coupon services/probe readings.
 - (C) For better understanding and ease of data interpretation, color coding/highlighting the tables should be used in corrosion coupon reports or assessments (green for low, yellow for moderate and red for high).

Section 6: Other Recommendations and Important Considerations

- 6.1** Internal corrosion monitoring programs must be established in oil and gas companies to minimize internal corrosion risks and set periodic mitigation plans.
- 6.2** HSE aspects must always be in consideration while carrying out coupon retrieval/servicing. Hazard analysis and risk assessments should be completed for each retrieval case. Higher level reviews may be necessary for circumstances where high system pressures or temperatures or particularly dangerous or toxic fluids are present.
- 6.3** Corrosion monitoring access fittings (coupons and probes) should be minimized in high pressure transmission gas pipelines (discussed in [Paragraph 3.4.9](#)).
- 6.4** Sampling points shall be installed at corrosion monitoring stations for sample collection for analysis. This is beneficial for corrosion assessments and correlation between corrosivity of the process stream environment and the corrosion/pitting rates from corrosion coupons or probes.
- 6.5** Accessibility considerations for corrosion monitoring stations shall be made (portable hop-ups/stands, access pits or permanent access platforms (as per company’s specifications or requirements), as they are essential for ensuring periodic servicing of corrosion monitoring access fittings (coupon retrieval and probe data collection) and should be taken into consideration/implemented for new or existing facilities. (Examples can be seen in Figures 9A, 9B, 9C and 9D).



Figure 9A: Portable Hop-up/Stand (0.5 m to 1 m)



Figure 9B and 9C: Concrete Access Pits (1.8 m to 2 m height)



Figure 9D: Permanent Access Platform

Note: ^(A) Access pits shall be addressed as may be required by corporate protocols for confined space entry.

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^(B) Figure 9D above is good example of a low elevation work platform. Extraction equipment could be lifted by hand from grade level to the work platform. For work platforms at higher levels, where extraction equipment cannot be lifted to the platform, a davit shall be installed to safely lift all tools from grade level.

- 6.6** Photographs should be taken for each coupon before/after cleaning and archive with all relevant process data and lab analysis for future references. Conclusions on type of prevalent damages on corrosion coupons should be based on evidence from laboratory analysis and/or applicable testing (see [Appendix B](#)).
- 6.7** Severity of corrosion observed on corrosion coupons should be correlated with the exposure period, as the severity can often be misleading. For example, a corrosion coupon found corroded with a high corrosion rate, but the exposure period is 5 years. The finding does not necessarily mean the corrosion is aggressive, but the corrosion coupon corroded due to a long exposure period in the process stream environment.
- 6.8** Installation of corrosion monitoring stations or monitoring coupon corrosion/pitting rate trends should not be carried out in internally coated piping and pipelines, as it will provide inaccurate conclusions (coupons are exposed holidays and are expected to corrode in such conditions). However, one or few locations may be utilized to monitor deposition, unusual observations or bacterial proliferation.
- 6.9** Corrosion monitoring stations are typically not installed on corrosion resistant alloyed piping and pipelines. Corrosion Resistant Alloys (CRAs) such as UNS S31603, UNS N06625, UNS N08825, UNS N04400, UNS C69100, UNS R50250 gr 1, UNS R50400 gr 2, UNS N10276, etc. are selected to mitigate internal corrosion risks in highly corrosive environments due their inherently high resistance to corrosion. As such; corrosion and pitting rates would be anticipated to be too low to effectively monitor. The piping itself can be monitored externally by other methods for evidence of corrosion. However, where corrosion inhibitor is being added to protect downstream carbon steel, that inhibitor is typically added to CRA or alloy clad piping spools and the only place to obtain uninhibited corrosion rates is upstream of that injection point. In those circumstances, an alloy monitoring station with carbon steel coupons will be installed. Corrosion rates determined from the coupons thus exposed will be used to compare with rates obtained from coupons exposed in the carbon steel treated part of the system.
- 6.10** Adequate engineering reviews are required when considering the installation of corrosion monitoring access fittings directly on equipment, vessels or tanks shell. In liquid filled or intermittently liquid-flooded areas, mounting attachments and fitting bores can act as deadlegs, prone to stagnation and deposit accumulation. Unrepresentatively high corrosion rates within deposits not typically present in a bulk liquid phase or corrosion of mounting attachments leading to costly repair of a pressure vessel can occur. Monitoring in locations not prone to liquid stagnation and/or deposit accumulation, i.e., wet gas phases, could be monitored, but can have accessibility issues which may significantly restrict servicing opportunities. If piping attached to the equipment, vessel or tank shell contains the same phase for which monitoring is required, installation on that piping may be a better option.
- 6.11** Should a short-lived facility exceed its design life by more than 10% without termination, corrosion coupon trends shall be assessed for implementing proper mitigation plans to ensure continuous operations.

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⁽⁵⁾ American Gas Association (AGA), 400 N. Capitol St. NW, Washington, DC 20001, www.aga.org.

Appendix A

Typical Corrosion Coupon Report (Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

☐ Well ☐ Flowline ☐ Pipeline ☐ Facility

Well, Flowline, Facility or Pipeline Number _____

Well, Flowline, Facility or Pipeline Type _____

Flow Rates—Oil, m³/d (BOPD) _____ Water, m³/d (BWPD) _____

Gas, m³/d (MMCFPD) _____ Temperature _____ °C (°F) Pressure _____ MPa (psig)

Fluid analysis (attach if lengthy)

Gas analysis (attach if lengthy)

Coupon location in system

Sketch of system with coupon location attached

☐ Yes ☐ No

Coupon number _____ Material _____

Surface finish _____ Exposed area _____

Dimensions _____

Installation Date _____ Installation Mass _____

Removal Date _____

Removal Mass _____

Days in System _____

Mass after cleaning _____

Mass loss _____

Average corrosion rate: _____ mm/y (mpy)

Deepest measured pit _____ mm (mil)

Maximum pitting rate _____ mm/y (mpy)

Description of deposit before cleaning

Analysis of deposit

Description of coupon after cleaning (e.g., etch, pitting, erosion, etc.)

Chemical treatment during exposure

Other remarks

Appendix B

Corrosion Coupon Photographs (Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

Note: Bacterial Proliferation for planktonic and sessile bacteria carried out in accordance with NACE standards TM0194 and TM0106.

B1) New Coupons (Strip & Flush Disk)

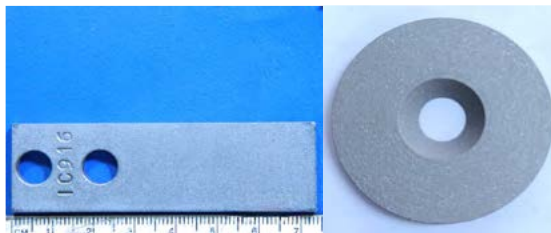


Figure B1

- B2)** Service: Brackish water tank outlet
Corrosion Rate: 1 mpy
Pitting rate: 7 mpy
Exposure Period: 208 days
Findings: High chloride content, pH 5.7, sulfate reducing bacteria (SRB) 10,000 counts/ml, acidic environment.
Conclusion: Low corrosion rate despite highly acidic environment, excessive SRB counts and long exposure, as the adhered chlorides layer hardened and prevented corrosion. Nevertheless, the process stream identified as highly corrosive.

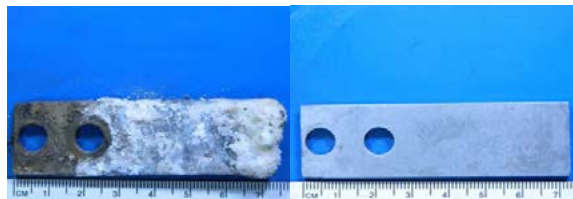


Figure B2

- B3)** Service: Recycle water outlet from 2nd stage desalter
Corrosion Rate: 3 mpy
Pitting Rate: 7 mpy
Exposure Period: 109 days
Findings: High chloride content, pH 6.3
Conclusion: Typical uniform corrosion on coupons with moderate corrosion rate.

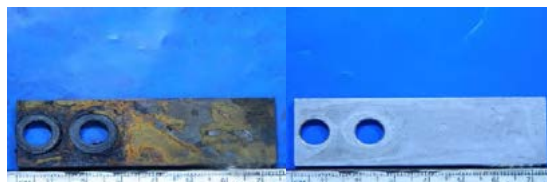


Figure B3

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- B4)** Service: Brackish water to desalters
Corrosion Rate: 4 mpy
Pitting rate: 13 mpy
Exposure Period: 87 days
Findings: High chloride content, pH 6.8
Conclusion: Typical uniform corrosion on coupons with moderate corrosion rate.



Figure B4

- B5)** Service: Brackish water inlet to desalters
Corrosion Rate: 1 mpy
Pitting Rate: 15 mpy
Exposure Period: 39 days
Findings: High chlorides & water contents, pH 6.8,
Conclusion: Typical pitting corrosion on coupons with high pitting rate in short term exposures.

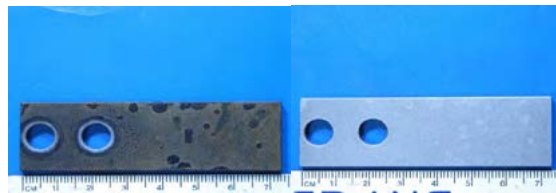


Figure B5

- B6)** Service: Crude flowline heading to oil gathering center
Corrosion Rate: 1 mpy
Pitting Rate: 27 mpy
Exposure Period: 203 days
Findings: High chlorides & water content, pH 6.2, long exposure period
Conclusion: Crevice corrosion and pitting under washer, with few isolated pits scattered on the coupon. Under washer crevice, corrosion occurs due to bends in the washer, water entrapment beneath the washer or improper tightening during installation (See B7).

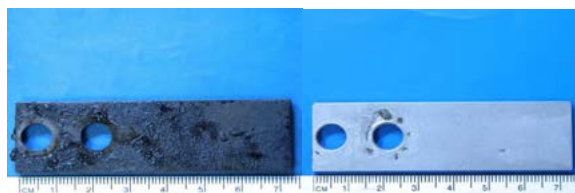


Figure B6

- B7)** Typical crevice corrosion or pitting propagation under washers.

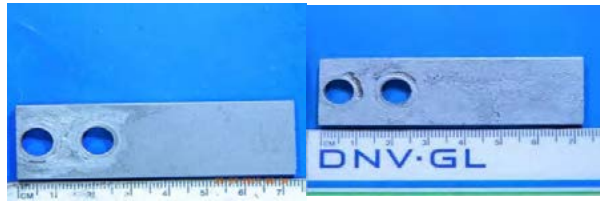


Figure B7

- B8)** Service: Brackish water to desalters
Corrosion Rate: 20 mpy
Pitting rate: 98 mpy
Exposure Period: 473 days
Findings: High chloride content, pH 6.8
Conclusion: Extremely high corrosion & pitting rates due to long exposure period in the process environment.



Figure B8

- B9)** Service: Recycle water from 2nd stage desalter into crude heading to 1st stage desalter
Corrosion Rate: 20 mpy
Pitting rate: 68 mpy
Exposure Period: 60 days
Findings: High chloride content, pH 6.2, general aerobic bacteria (GAB) and general anaerobic bacteria (GAnB) 10 counts/cm²
Conclusion: MIC. Extremely high corrosion & pitting rates in a slightly acidic environment, influenced by presence of bacteria.

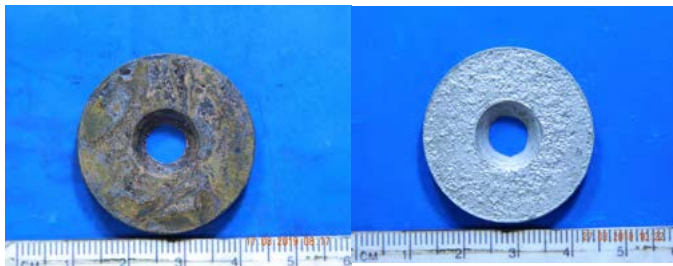


Figure B9

- B10)** Service: Effluent water heading to disposal well
Corrosion Rate: 184 mpy
Pitting rate: 509 mpy
Exposure Period: 91 days
Findings: H₂S content 0.05 ppm, pH 5.8
Conclusion: Extremely high sour corrosion.

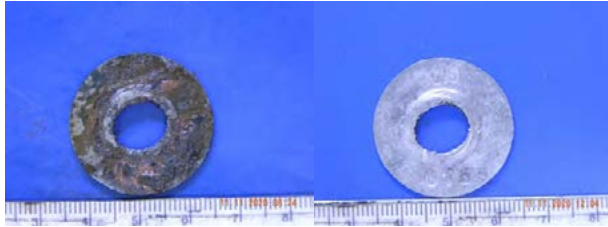


Figure B10

- B11)** Service: Effluent water to exchanger before desalters
Corrosion Rate: 250 mpy
Pitting rate: 682 mpy
Exposure Period: 60 days
Findings: High chlorides content, pH 5, sulfate reducing bacteria (SRB) 100 counts/ml, H₂S 0.03 ppm, acidic environment
Conclusion: MIC. Extremely high corrosion & pitting rates due to highly acidic environment, influenced by presence of SRB.

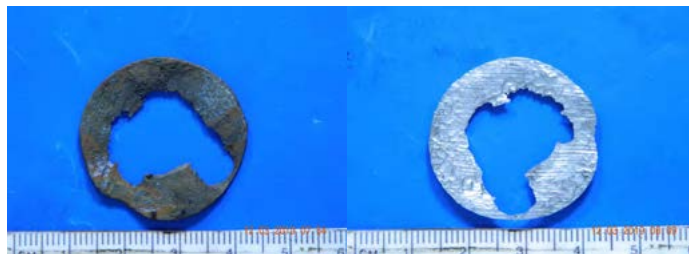


Figure B11

- B12)** Service: Effluent water outlet from wet tank
Corrosion Rate: 246 mpy
Pitting rate: 843 mpy
Exposure Period: 55 days
Findings: High chlorides & waters contents, pH 5.5, general anaerobic bacteria (GAnB) 1,700 counts/cm², acidic environment
Conclusion: MIC. Extremely high corrosion and pitting rates due to a highly acidic environment, influenced by presence of GAnB.



Figure B12

- B13)** Service: Water drain from separator
Corrosion Rate: < 1 mpy
Pitting rate: < 1 mpy
Exposure Period: 218 days
Findings: Ashphaltene, pH 6.9, H₂S 120 ppm
Conclusion: Low rates due to the adhered ashphaltene protective layer preventing corrosion despite sour environment and long exposure period.

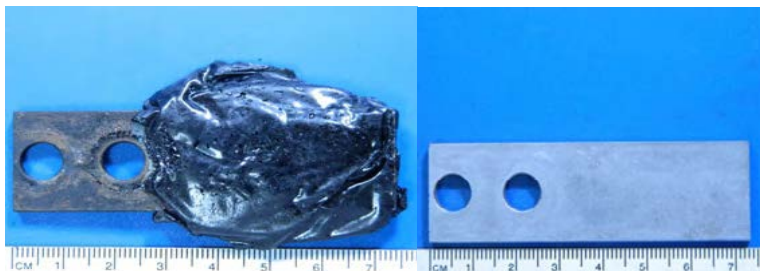


Figure B13

- B14)** Service: Recycle water outlet from desalter
Corrosion Rate: 1 mpy
Pitting rate: 33 mpy
Exposure Period: 133 days
Findings: High chlorides, sulfate & water contents, pH 5.8, sulfate reducing bacteria (SRB) 17 counts/cm², H₂S 36 ppm, acidic environment
Conclusion: Low corrosion rate due to iron sulfide (FeS) adhered deposits providing a protective layer. Additionally, elemental sulfur found scattered on the coupon, leading to isolated pitting and under washer crevice corrosion. The iron sulfide and elemental sulfur (S₈) formation is highly likely due to SRB action, production of H₂S, reaction with water and oxidation.

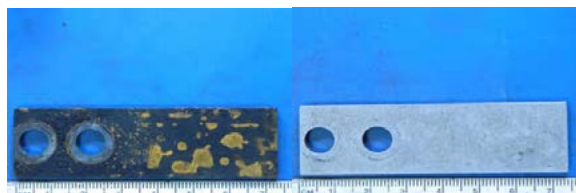


Figure B14

- B15)** Service: Condensate export pipeline
Corrosion Rate: 234 mpy
Pitting rate: 312 mpy
Exposure Period: 221 days
Findings: High chlorides, sulfates & water contents, pH 5.4, H₂S 480 ppm, elemental sulfur (S₈), acidic environment
Conclusion: Extremely high general corrosion and pitting rates due formation of elemental sulfur, possible presence of sulfuric acid and long exposure period.

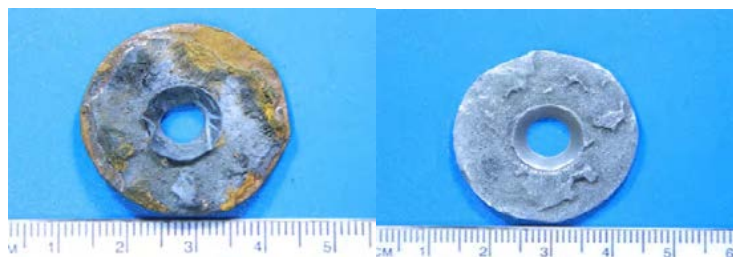


Figure B15

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- B16)** Service: Crude inlet to wet tank
Corrosion Rate: 241 mpy
Pitting rate: 1,100 mpy
Exposure Period: 42 days
Findings: High chlorides & water contents, pH 6, general anaerobic bacteria (GAnB) 38,000 counts/cm², H₂S 16 ppm, acidic environment
Conclusion: MIC. Extremely high general corrosion and pitting rates due to the excessive GAnB presence in an acidic environment. The morphology on the coupon possibly a pattern for GAnB damage.

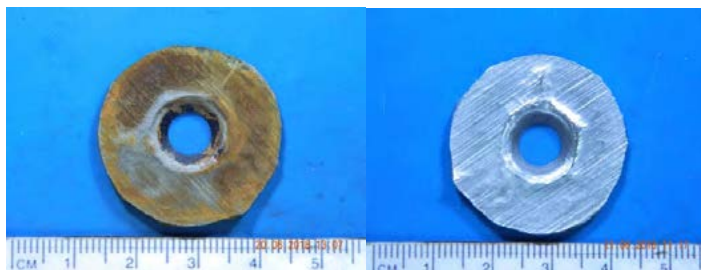


Figure B16

- B17)** Service: Effluent water outlet from 1st stage desalter
Corrosion Rate: 74 mpy
Pitting rate: 610 mpy
Exposure Period: 76 days
Findings: High chlorides, sulfates & water contents, pH 5.8, general anaerobic bacteria (GAnB) 1,000 counts/cm², H₂S 21 ppm, acidic environment
Conclusion: MIC. Extremely high general corrosion and pitting rates due to the significant GAnB presence in an acidic environment. This is another photograph showing similar damage morphology to coupon # 12 and coupon #16 for possible GAnB damage pattern. Further, the high amount of sulfate and H₂S contents could be a sign for sulfate reducing bacteria (SRB), which was not detected in the sessile analysis on the coupons or fluid analysis. However, SRB found upstream in the process could have influenced corrosion (in the form of isolated pitting), as can be seen in the photograph.



Figure B17

- B18)** Service: Crude flowline heading to oil gathering center
Corrosion Rate: 4 mpy
Pitting rate: 295 mpy
Exposure Period: 157 days
Findings: High chlorides, sulfates & water contents, pH 5.9, H₂S 33 ppm, acidic environment
Conclusion: Moderate corrosion rate despite acidic environment and long exposure period. However, the coupon was exposed to extremely high pitting rate at the crude - water interface, which also provided useful information on the water accumulated on the bottom surface of the piping (approximately 10 cm).

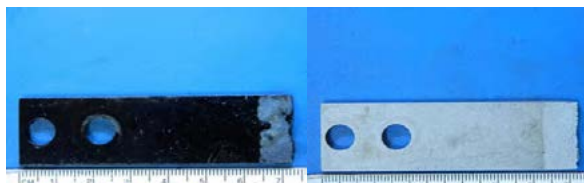


Figure B18

- B19)** Service: Wet crude tank shell
Corrosion Rate: 254 mpy
Pitting rate: 1,288 mpy
Exposure Period: 36 days
Findings: High chlorides & water contents, pH 5.9, general aerobic bacteria (GAB) and general anaerobic bacteria (GAnB) 380 counts/cm², H₂S 36 ppm, acidic environment
Conclusion: MIC. Extremely high general corrosion and pitting rates due to the influence GAB & GAnB in an acidic environment. The access fitting at the tank shell was a deadleg in stagnant condition with water and deposit accumulation, which likely expedited the corrosion mechanisms on the coupon.

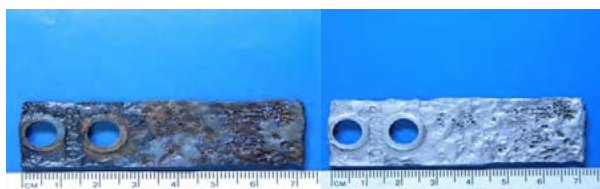


Figure B19

- B20)** Service: Gas outlet from compressor to dehydration unit
Corrosion Rate: 8 mpy
Pitting rate: 40 mpy
Exposure Period: 127 days
Findings: High chlorides, sulfates & water contents, pH 5.3, general aerobic bacteria (GAB) 380 counts/cm² and general anaerobic bacteria (GAnB) 3,800 counts/cm², H₂S 76 ppm, elemental sulfur (S₈), acidic environment
Conclusion: MIC. High general corrosion rate, extremely high pitting rates, due to the influence GAB & GAnB in an acidic environment containing elemental sulfur and long exposure period.



Figure B20

- B21)** Service: Crude inlet to wet tank
Corrosion Rate: 1 mpy
Pitting rate: 17 mpy
Exposure Period: 230 days
Findings: Presence of iron sulfides (mackinawite), high chloride & water contents, pH 5.7, H₂S 14 ppm, acidic environment
Conclusion: Extremely high pitting rate and localized corrosion under deposits at scattered areas on the coupon. The iron sulfide adhered layer prevented accelerated corrosion despite the acidic environment and long exposure period.

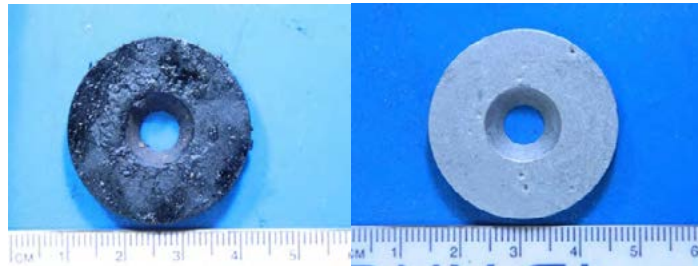


Figure B21

- B22)** Service: Gas export pipeline
Corrosion Rate: 8 mpy
Pitting rate: 11 mpy
Exposure Period: 107 days
Findings: Presence of iron sulfides (mackinawite), general corrosion and pitting rates in the moderate – high borderline, low chlorides & water contents, pH 5.3, H₂S 62 ppm, acidic environment
Conclusion: Under deposit sour corrosion. The iron sulfide adhered layer prevented accelerated corrosion on the coupon despite acidic environment, significant H₂S content and long exposure period. Similar damages anticipated across the length of the export pipeline.

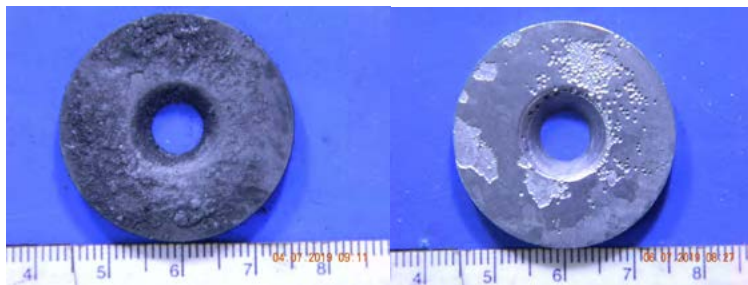


Figure B22

- B23)** Service: Crude flowline heading to oil gathering center
Corrosion Rate: 70 mpy
Pitting rate: 1,104 mpy
Exposure Period: 42 days
Findings: High chloride, sulfates & water contents, pH 5.8, sulfate reducing bacteria (SRB) 1,000 counts/ml, general aerobic bacteria (GAB) 10,000 counts/ml and general anaerobic bacteria (GAnB) 10,000 counts/ml, acidic environment
Conclusion: MIC. Extremely high general corrosion and pitting rates due to the influence of SRB, GAB & GAnB in an acidic environment, leading to the observed damages and under washer crevice corrosion.

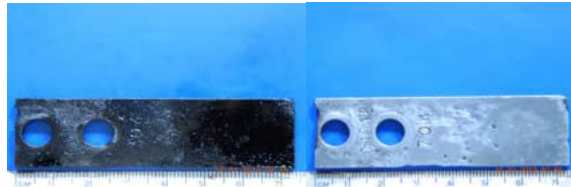


Figure B23

- B24)** Service: Recycle water outlet from 2nd stage desalter
Corrosion Rate: 2 mpy
Pitting Rate: 26 mpy
Exposure Period: 191 days
Findings: High sulfates & water contents, pH 6, SRB 17,000 counts/cm², acidic environment
Conclusion: Localized corrosion aggravated under deposit, tubercles, or biofilm due to MIC and propagated under washers.

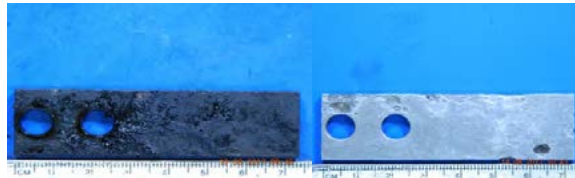


Figure B24

- B25)** Service: Crude flowline to oil gathering center
Corrosion Rate: 13 mpy
Pitting Rate: 653 mpy
Exposure Period: 71 days
Findings: High chlorides, sulfates & water contents, pH 5.3, general aerobic bacteria (GAB) 170 counts/cm², acidic environment
Conclusion: Localized corrosion aggravated under deposit, tubercles or biofilm due to MIC. Also, extremely high pitting corrosion at the crude-water interface.

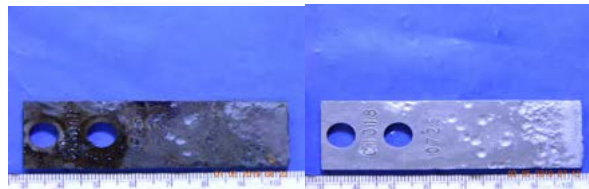


Figure B25

- B26)** Service: Effluent water outlet from wet crude tank
Corrosion Rate: 42 mpy
Pitting Rate: 355 mpy
Exposure Period: 63 days
Findings: High chlorides sulfates & water contents, pH 5.8, sulfate reducing bacteria (SRB) 17 counts/cm², general aerobic bacteria (GAB) 1,700 counts/cm² and general anaerobic bacteria (GAnB) 17,000 counts/cm², acidic environment
Conclusion: Localized pitting aggravated under deposits, tubercles, or biofilm due to MIC. The coupon is exposed to different damage morphologies due to the different types of bacteria present. The damage morphology inside the large pits is similar to coupons #12, #16 and #17 for possible GAnB damage pattern.

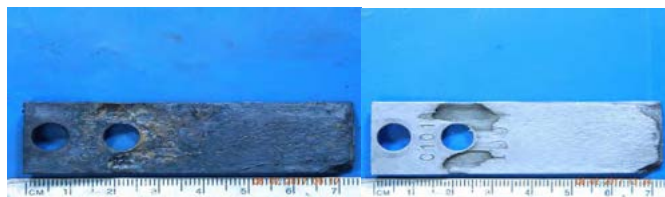


Figure B26

- B27)** Service: Effluent water to well injection
Corrosion Rate: 74 mpy
Pitting Rate: 662 mpy
Exposure Period: 63 days
Findings: High chlorides, sulfates & water contents, pH 5.8, sulfate reducing bacteria (SRB) 17 counts/cm², general aerobic bacteria (GAB) 1,700 counts/cm² and general anaerobic bacteria (GAnB) 17,000 counts/cm², acidic environment
Conclusion: MIC. Downstream of coupon # 25.

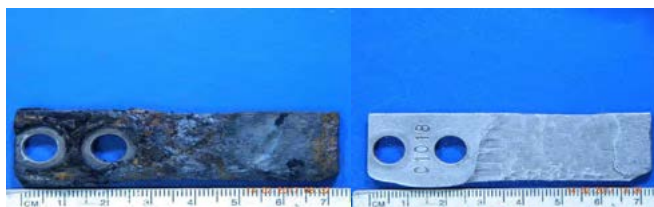


Figure B27

- B28)** Service: Crude flowline heading to oil gathering center
Corrosion Rate: 5 mpy
Pitting Rate: 31 mpy
Exposure Period: 195 days
Findings: High chlorides, sulfates & water contents, pH 6.2, general aerobic bacteria (GAB) 17 counts/cm² and general anaerobic bacteria (GAnB) 170 counts/cm², slightly acidic environment, long exposure period
Conclusion: Localized corrosion, crevice corrosion under washer, aggravated under deposit, tubercles or biofilm due to MIC.

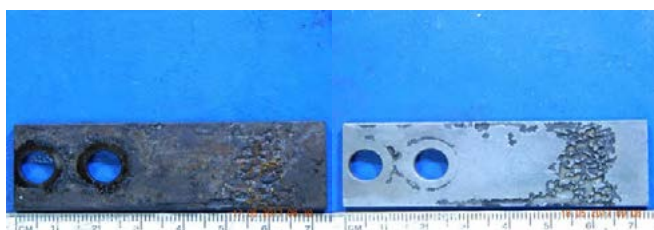


Figure B28

- B29)** Service: Crude flowline heading to oil gathering center
Corrosion Rate: 9 mpy
Pitting Rate: 227 mpy
Exposure Period: 204 days
Findings: High chlorides, sulfates & water contents, pH 6, general aerobic bacteria (GAB) 170 counts/cm² and general anaerobic bacteria (GAnB) 170 counts/cm², slightly acidic environment, long exposure period
Conclusion: MIC. Localized corrosion at bacteria biofilm.

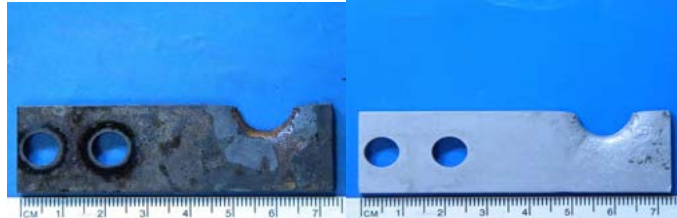


Figure B29

- B30)** Service: Crude flowline heading to oil gathering center
Corrosion Rate: 1 mpy
Pitting Rate: 228 mpy
Exposure Period: 203 days
Findings: High chlorides, sulfates & water contents, pH 6, general aerobic bacteria (GAB) 170 counts/cm² and general anaerobic bacteria (GAnB) 170 counts/cm², slightly acidic environment, long exposure period
Conclusion: Localized corrosion and crevice corrosion under washer aggravated under deposit, tubercles or biofilm due to MIC.

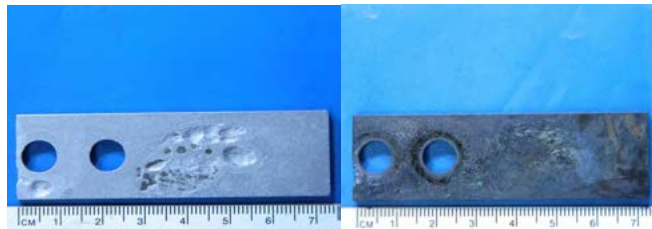


Figure B30

- B31)** Service: Crude outlet from wet tank to export
Corrosion Rate: 202 mpy
Pitting Rate: 483 mpy
Exposure Period: 96 days
Findings: High chlorides, sulfates & water contents, pH 5.8, sulfate reducing bacteria (SRB) 3,800 counts/cm², general aerobic bacteria (GAB) 3,800 counts/cm² and general anaerobic bacteria (GAnB) 3,800 counts/cm², acidic environment
Conclusion: Extremely high general & pitting corrosion due to MIC.

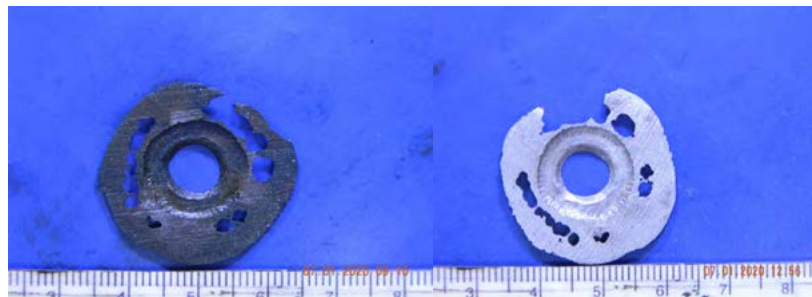


Figure B31

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- B32)** Service: Effluent water outlet from wet crude tank
Corrosion Rate: 147 mpy
Pitting Rate: 760 mpy
Exposure Period: 61 days
Findings: High chlorides, sulfates & water contents, pH 5.9, sulfate reducing bacteria (SRB) 38 counts/cm², general aerobic bacteria (GAB) 38 counts/cm² and general anaerobic bacteria (GAnB) 3,800 counts/cm², acidic environment
Conclusion: Extremely high general & pitting corrosion due to MIC.

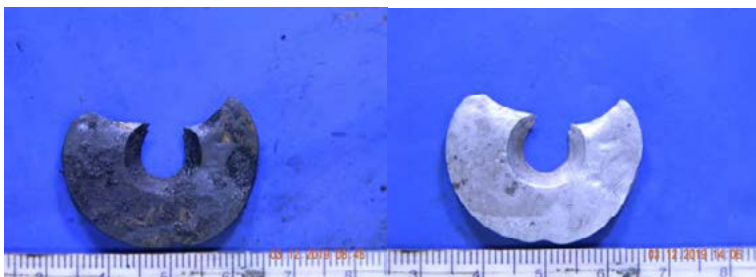


Figure B32

- B33)** Service: Wet crude tank shell
Corrosion Rate: 149 mpy
Pitting rate: 539 mpy
Exposure Period: 86 days
Findings: High chlorides, sulfates & water contents, H₂S 26 ppm, pH 6.1, slightly acidic environment
Conclusion: Extremely high general corrosion and pitting rates due to stagnation. The access fitting at the tank shell was a deadleg in stagnant condition with water and deposit accumulation expediting the corrosion mechanisms on the coupon.

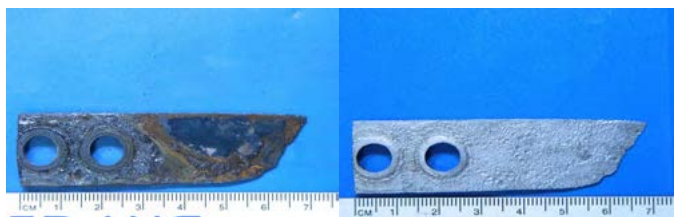


Figure B33

- B34)** Service: Crude inlet to 1st stage desalter
Corrosion Rate: 28 mpy
Pitting Rate: 27 mpy
Exposure Period: 182 days
Findings: High chlorides, sulfates & water contents, pH 6, general anaerobic bacteria (GAnB) 3,800 counts/cm², slightly acidic environment
Conclusion: Extremely high general & pitting corrosion due to MIC. The damage morphology on the coupon possibly a pattern for GAnB damage, similar to coupons #12, #16, #17 and #26.

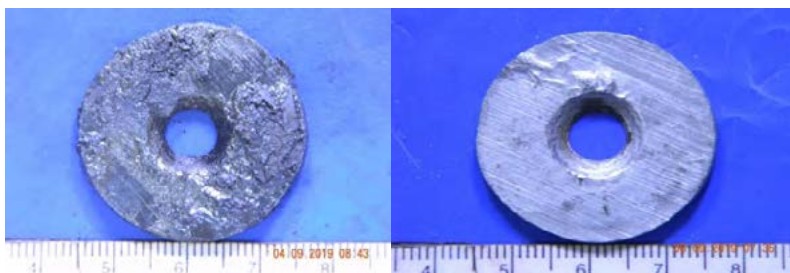


Figure B34-B35) Hydrogen Blistering in Amine treatment unit - Rich Amine outlet from contactor (Example 1)

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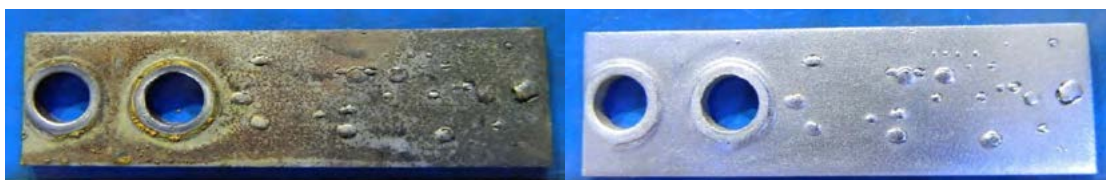


Figure B35

B36) Hydrogen Blistering in Amine treatment unit - Rich Amine outlet from contactor (Example 2)

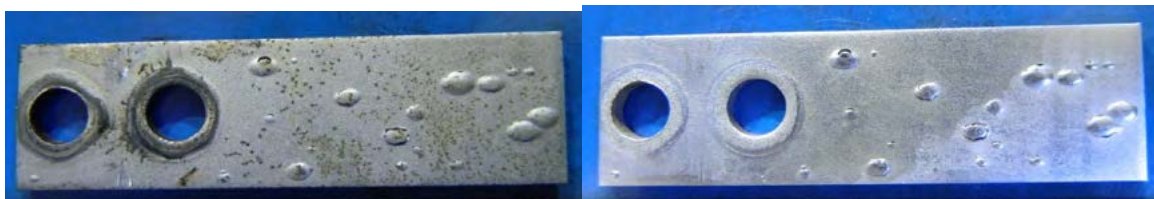


Figure B36

B37) Hydrogen Blistering in Amine treatment unit - Rich Amine outlet from contactor (Example 3)



Figure B37

B38) Hydrogen Blistering in Amine treatment unit - Rich Amine outlet from contactor (Example 4)



Figure B38

B39) Cracking in Amine treatment unit - Rich Amine outlet from contactor

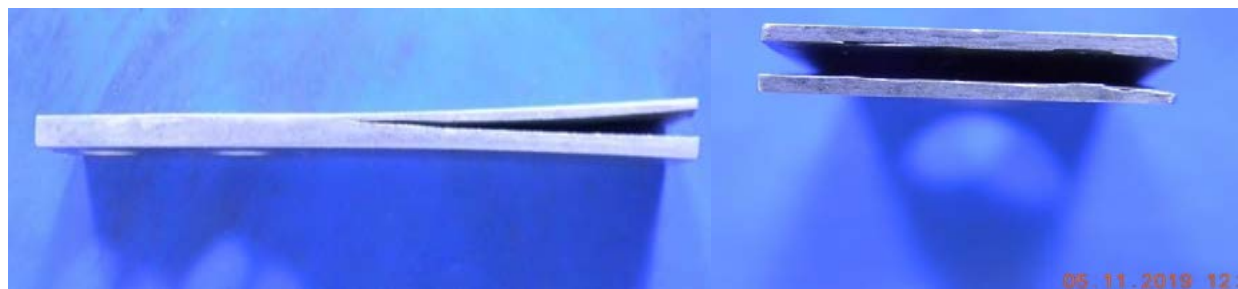


Figure B39

B40) Cracking in Amine treatment unit - Amine Flash Tank

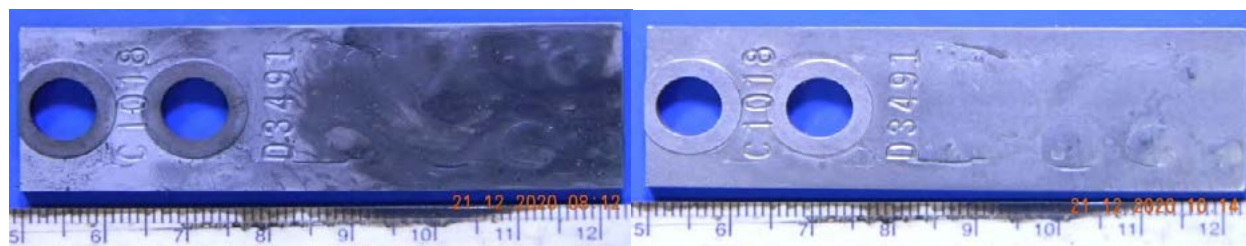


Figure B40