



**NACE Standard RP0775-2005
Item No. 21017**

Standard Recommended Practice

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

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Foreword

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

This standard was originally prepared in 1975 by NACE Task Group T-1C-6, a component of Unit Committee T-1C on Detection of Corrosion in Oil Field Equipment, to provide procedures for the preparation, installation, and analysis of corrosion coupons. It was revised by Task Group T-1C-11 in 1986 and by T-1C-23 in 1991. T-1C was combined with Unit Committee T-1D on Corrosion Monitoring and Control of Corrosion Environments in Petroleum Production Operations, and this standard was revised by Task Group T-1D-54 in 1999. It was reaffirmed in 2005 by Specific Technology Group (STG) 31 on Oil and Gas Production—Corrosion and Scale Inhibition. This standard is issued by NACE International under the auspices of STG 31.

In NACE standards, the terms *shall*, *must*, *should*, and *may* are used in accordance with the definitions of these terms in the NACE Publications Style Manual, 4th ed., Paragraph 7.4.1.9. *Shall* and *must* are used to state mandatory requirements. The term *should* is used to state something good and is recommended but is not mandatory. The term *may* is used to state something considered optional.

NACE International Standard Recommended Practice

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Section 1: General

1.1 This standard is presented for the use of corrosion coupons in oilfield drilling, production, and transportation operations. Oilfield operations include oil-, water-, and gas-handling systems, and drilling fluids. (When used in this standard, *system* denotes a functional unit such as 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.) Corrosion coupon testing consists of the exposure of a small specimen of metal (the coupon) to an environment of interest for a period of time to determine the reaction of the metal to the environment. Corrosion coupons are used to evaluate corrosiveness of various systems, to monitor the effectiveness of corrosion-mitigation programs, and to evaluate the suitability of different metals for specific systems and environments. The coupons may be installed in the system itself or in a special test loop or apparatus. Corrosion rates shown by coupons and most other corrosion-monitoring devices seldom duplicate the actual rate of corrosion on the system piping and vessels. Accurate system corrosion rates can be determined by nondestructive measurement methods or failure frequency curves. Data furnished by corrosion coupons and other types of monitors must be related to system requirements. High corrosion rates on coupons may be used to verify the need for corrective action. If a corrosion-mitigation program is initiated and subsequent coupon data indicate that corrosion has been reduced, 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}

1.2 This standard describes preparation and handling techniques for metal coupons prior to and following exposure. Corrosion rate calculations and a typical form for recording data are also included.

1.3 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 mass-loss determination. Coupons may be used alone but they should be used in conjunction with other monitoring methods such as test nipples, hydrogen probes, galvanic probes, polarization instruments, resistance-type corrosion monitors, chemical analysis of process streams and nondestructive metal thickness measurements, caliper surveys, and corrosion failure records.

1.4 Corrosion coupons used as recommended in this standard measure the total metal loss during the exposure period. They show corrosion that has already occurred. A single coupon cannot be used to determine whether the rate of metal loss was uniform or varying during the exposure period. Information on the change in corrosion rate can be obtained by installing several coupons at one time and removing and evaluating individual coupons at specific short-term intervals. Other monitoring methods mentioned in Paragraph 1.3 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.

1.5 In addition to mass loss, important factors to consider in the analysis and interpretation of coupon data include location, time onstream, measured pit depth, surface profile (blistering, erosion), corrosion product and/or scale composition, and operating factors (e.g., downtime, system flow velocities, upsets, or inhibition).

1.6 Coupon corrosion rates in one system should not be compared directly with those in other unrelated systems. However, corrosion rates in similar systems (e.g., two systems handling identical environments) often correlate. Additional information can be obtained within a system by varying one exposure parameter at a time (e.g., location or duration of exposure). For example, corrosion rates can be affected by changes in fluid velocity within a system. Corrosion rates can vary dramatically upstream and downstream from the point of entry of a corrodent, such as oxygen.

Section 2: Processing of Corrosion Coupons

2.1 Coupon Preparation. The following procedure should be used to prepare coupons for corrosion testing. Coupons should be new; do not reuse coupons after exposure and analysis.

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 temperatures that could change the microstructure of the coupon.

2.1.2 Etch or stamp a permanent serial number on the 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 imposed stress.

2.1.2.3 Instances of SCC of carbon steel coupons under oilfield 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. Coupons formed by stamping are less expensive than machined coupons. Stamped coupons are satisfactory without additional machining for most oilfield monitoring.

2.1.4 Ideally, match the surface finish of the coupons with the finish of the metal being investigated, i.e., the pipe or vessel wall. Because this is seldom practical, other surface finishes are applied. No specific surface finish is absolutely essential but uniformity is very important when data from different sets of coupons are being compared. Coupons may be prepared by grinding smooth 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.

2.1.5 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.

2.1.6 Under a ventilated hood, remove any residual oils with a hydrocarbon solvent such as xylene, toluene, or 1,1,1 trichloroethane and rinse with anhydrous isopropyl alcohol. If oils are not present, cleaning with alcohol or acetone should be sufficient.

2.1.7 Dry, measure, and weigh the coupons to within ± 0.1 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.)

2.1.8 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 and After 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), and 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 2.1.5.)

2.2.3 When the coupon is removed, record the coupon serial number, removal date, observations of any erosion or mechanical damage, and appearance of scale or corrosion product. Any other pertinent data such as shut-in time and changes in velocity and inhibitor treatment should also be recorded.

The coupon should be photographed immediately after removal, particularly if appearance of the corrosion product or scale is important.

2.2.4 Protect the coupon from contamination by oxidation and handling. Place the coupon in a moisture-proof or special envelope impregnated with volatile corrosion inhibitor 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 desirable to remove moisture prior to shipment. Corrosion products or scale deposits should not be removed in the field.

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. Prior to any cleaning, weigh the coupon to within ± 0.1 mg.

2.3.2 Visually examine the coupon and record observations. Qualitative analysis of adherent scale or foreign material may be performed.

2.3.3 Immerse the coupon in a suitable hydrocarbon solvent, such as clean xylene or toluene, long enough to remove the oil, oil-wet materials, and paraffin. Rinse with isopropyl alcohol or acetone. Handle solvent under a ventilated hood. Dry in a gentle dry air stream and weigh the coupon to within ± 0.1 mg if quantitative analysis of acid-soluble deposits is desired.

⁽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.

2.3.4 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.^{4,5,6,7}

2.3.4.1 Coupons that are not coated with hard scale or tightly adhering corrosion products may be cleaned by blasting with glass beads. Mass loss during blast cleaning should be determined by cleaning unexposed coupons in accordance with Paragraph 2.3.7.

2.3.5 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.

2.3.6 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 Subject a preweighed blank that was 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 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 may be used to determine the average corrosion rate depending on the units desired.⁶

2.4.1.1 A calculation of average corrosion rate, expressed as a uniform rate of thickness loss per

unit time in millimeters per year or millimeters per annum (mm/y or mm/a), 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 or mm/a)

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 A calculation of average 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 (in.²)

T = exposure time, days (d)

D = density of coupon metal, grams per cubic centimeter (g/cm³)

2.4.1.3 A calculation of the average 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)

Table 1: Density of Metals^(A)

Material	Density, g/cm ³	Material	Density, g/cm ³
<u>Cast Irons</u>		<u>Copper Alloys</u>	
Gray cast iron	7.15	Admiralty brass	8.53
Malleable iron	7.27	Red brass, 85%	8.75
		Yellow brass	8.47
		Bronze—5% Aluminum	8.17
<u>Steels</u>		Bronze-Phosphor 10%	8.78
Carbon steel	7.86	Copper-Nickel (90-10)	8.84
Low-alloy steels	7.85	Cast Al-Bronze	7.80
9 Cr-1 Mo	7.67	Beryllium Copper	8.35
5 Ni	7.98		
9 Ni	8.10		
<u>Stainless steels</u>		<u>Other Materials</u>	
UNS ^(B) S30400 (Type 304)	7.90	Aluminum (Al)	2.70
UNS S31600 (Type 316)	8.00	Magnesium (Mg)	1.74
UNS S32100, S34700 (Types 321, 347)	8.02	Nickel (Ni)	8.90
UNS S41000 (Type 410)	7.70	Zinc (Zn)	7.13
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, 9639 Kinsman Rd., Materials Park, OH 44073-0002).

^(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), 400 Commonwealth Drive, Warrendale, PA 15096.

2.4.1.4 A calculation of the average 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 (in.²)

T = exposure time, days (d)

2.4.1.5 Conversion Factors^{8,9,10}

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.

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

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

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. 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. 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. Pit density per unit area should be reported. Additional information on the measurement of pits can be found in ASTM⁽²⁾ G 46.¹¹

2.5.3 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, care should be exercised in applying calculated pitting rates to project time-to-failure.

Section 3: Installation of Corrosion Coupons

3.1 Types of Corrosion Coupons

3.1.1 Corrosion coupons are available from a number of suppliers. 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. 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.

3.1.2 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.

3.1.3 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

3.1.4 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 An oil-resistant

elastomer should be used if hydrocarbons are present. 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. 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

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.

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

3.3.1.1 Adequate support of the coupons in the system.

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

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

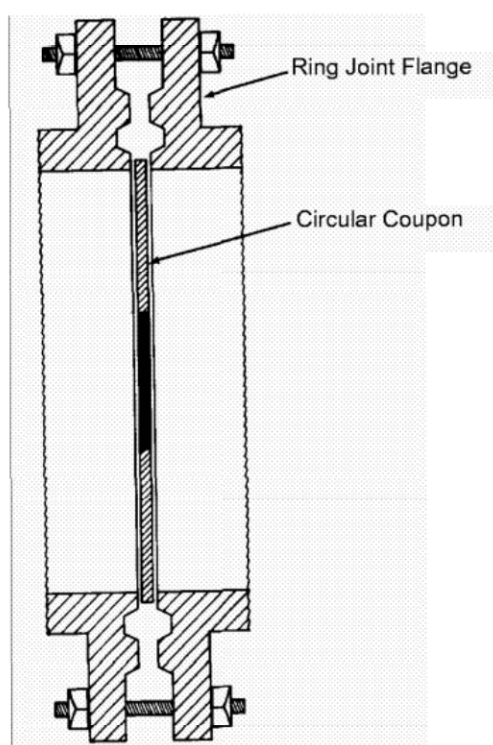
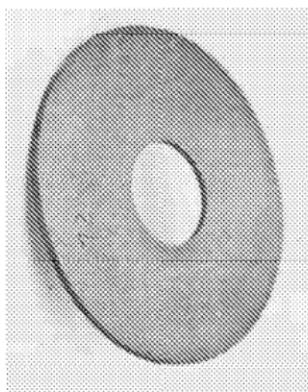


FIGURE 1: Circular (washer-type) coupon and typical mounting in a ring joint flange.

3.3.1.2 Electrical isolation of the coupon from other coupons, from the coupon holder, and from the pipe or vessel wall, to prevent galvanic corrosion.

3.3.1.3 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).

3.3.1.4 Provision for easy and rapid changing of coupons in the field.

3.3.2 Coupon holders like the one shown in Figure 3 should be marked so the coupon orientation can be determined when it is in service. (See Paragraph 3.4.6.)

3.3.3 The system must be depressurized prior to installation and removal of the coupons and coupon holders shown in Figures 3 and 4.

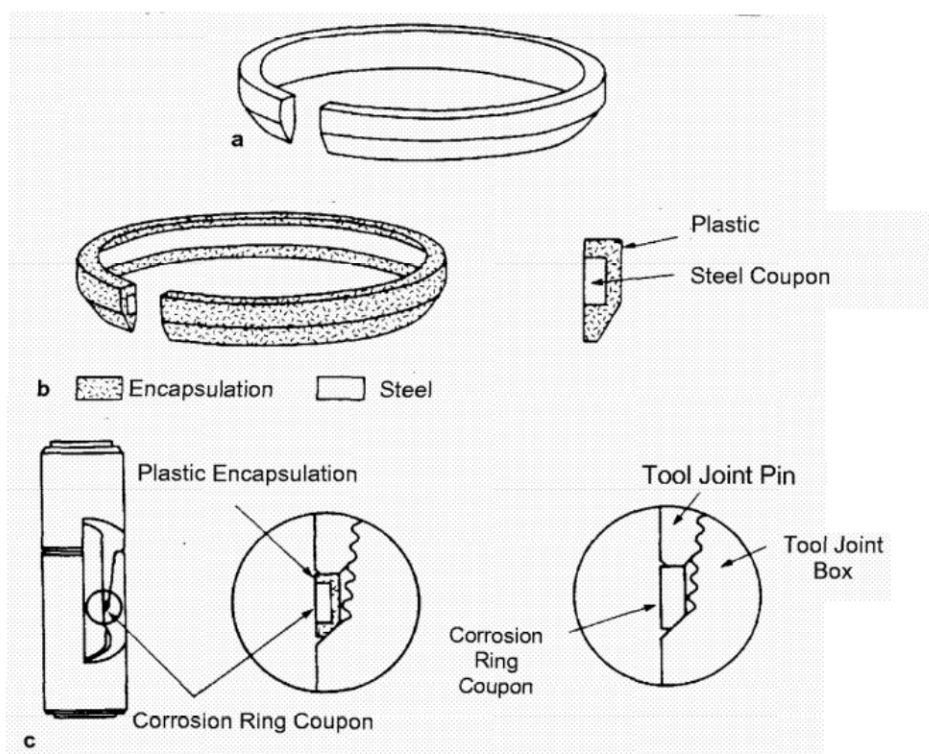


FIGURE 2: Drill pipe corrosion ring coupon: (a) steel corrosion ring (fabricated in accordance with API RP 13B-1); (b) steel corrosion ring coupon encapsulated in plastic; and (c) installed.

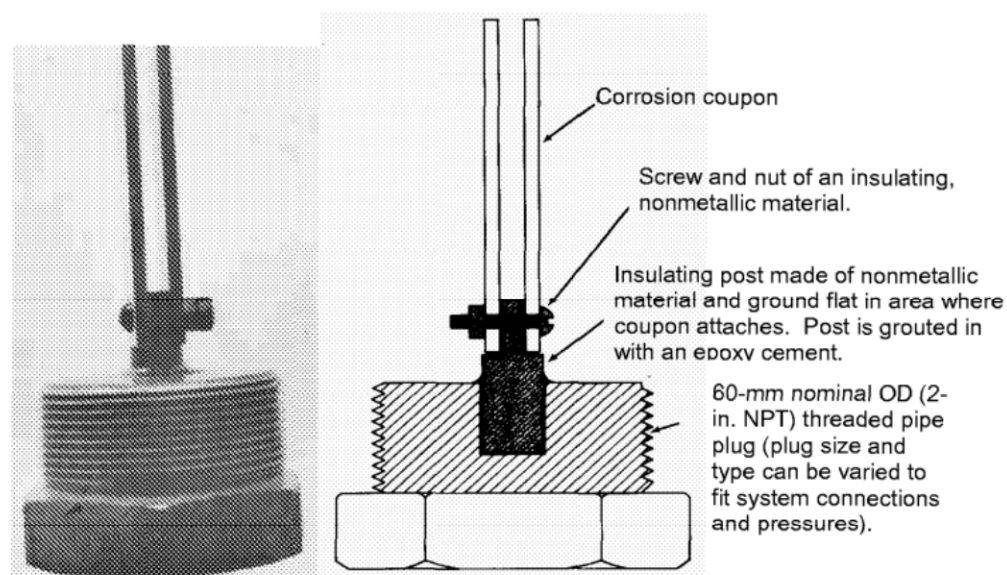


FIGURE 3: Flat coupon holder using a 60-mm nominal OD (2-in. NPT) threaded pipe plug. Also shows insulation method and attachment of corrosion coupon.

3.3.4 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 and 6. 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 contemplated, 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.

3.3.5 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. The disk-type coupons should be held in place with either plastic or coated steel screws. In some systems, iron sulfide may bridge between the coupon and pipe wall. The resulting short circuit can increase or decrease the rate of corrosion on the coupon.

3.3.6 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.

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 monitor, the coupons should be located where corrosion is occurring or is most likely to occur. Corrosion and design engineers should collaborate to ensure that sufficient access fittings for corrosion monitoring are included in the design of new facilities. In existing operating systems, corrosion failure records can identify corrosive areas. Ultrasonic and radiographic metal thickness measurements can be made to locate areas where corrosion has occurred. Coupons can function in either the liquid or vapor phase of a system. In new systems, experience with other similar systems can often be helpful. The following locations for coupons should be considered: (1) dead fluid areas; (2) high-velocity fluid streams and impingement points; (3) downstream from points of possible oxygen entry, such as tanks, pumps, vapor recovery units, and water makeup lines in gas sweetening systems; (4) 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; (5) amine and glycol streams that contain sour gas; (6) vapor sections in sour glycol regenerators; and (7) areas where a liquid/vapor interface occurs.

3.4.2 In lines handling wet gas, water can accumulate at changes in the line elevation as depicted in Figure 8. Corrosion may be accelerated where water has accumulated. Coupons in such systems must be located where they will be water-wet to correlate with corroding areas. Coupons located in the vapor phase could indicate only slight corrosion when water-wet areas are corroding severely.

3.4.3 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.

3.4.4 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, and phases.

3.4.5 Coupons located in flow lines of wells may be affected by paraffin accumulation. Coupons should be located in a section of the line that is free of paraffin deposits. Coupons located in surface lines from wells may not provide accurate information on downhole corrosion rates. However, trends can usually be identified.

3.4.6 Flat coupons should be oriented in the system so that one edge faces the fluid flow. Replacement coupons should have the same orientation as previous coupons. Records should indicate the exact location of the coupon in a line or vessel (i.e., top, middle, or bottom).

3.4.7 Corrosion in pipelines with small quantities of water is often monitored with test nipples (see Paragraph 3.6.1). Corrosion coupons must be carefully placed to ensure that they are subjected to the line's corrosive conditions. Coupons should be installed in both liquid and vapor phases.

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

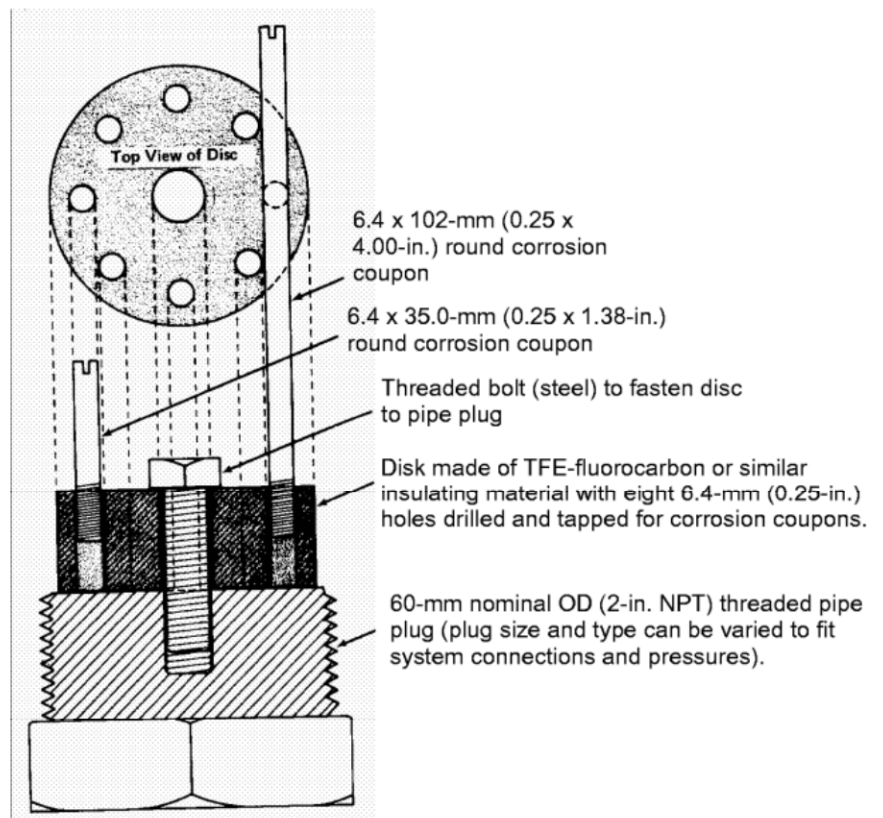
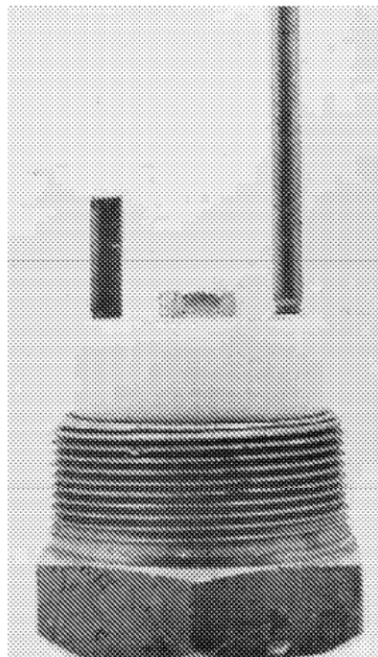


FIGURE 4: Round (rod-type) coupon holder using a 60-mm nominal OD (2-in. NPT) threaded pipe plug and special insulating disk that can accommodate eight round (rod-type) coupons.

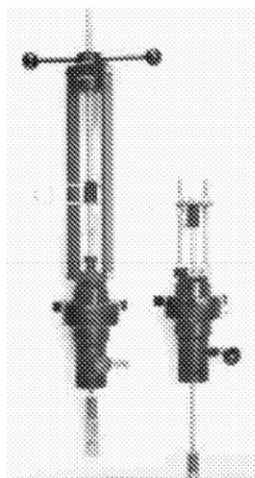


FIGURE 5: Tool for installing and removing coupons in systems under pressure. The pipe nipple screws into an existing valve on the line or vessel. Complete assembly is shown on left. After the coupon has been positioned, the drive unit is removed and the coupon holder is locked as shown on the right.

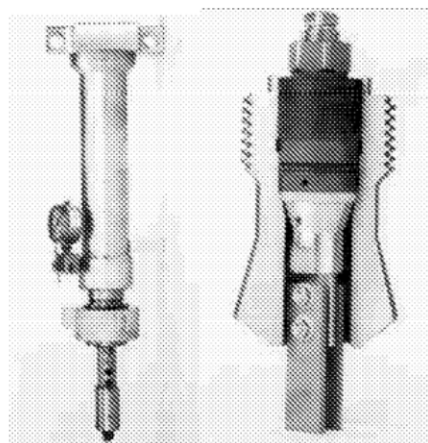


FIGURE 6: Extractor tool for inserting and removing coupons in systems under pressure: (a) insertion assembly used to install coupon holder in access fitting. Insertion assembly is removed after coupons are placed in access fitting; and (b) cutaway of special access fitting used with extractor tool. Fitting is welded to line or vessel. Shown with coupon and coupon holder installed.

3.4.8 In horizontal multiphase flow, phases can sometimes be stranded. Care must be taken to ensure the coupon is exposed to the corrosive phase(s). For example, in a 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. 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. Because exposure time affects test results, exposure periods should be as consistent as practical. A tolerance of $\pm 7\%$ allows a variation of ± 2 days on a 30-day exposure. This is satisfactory for most applications.

3.5.2 When coupons are used to evaluate and monitor corrosion-inhibitor treatment, new coupons should 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. 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.

3.6.1.1 Test nipples are usually exposed for longer periods (90 days to two years) than coupons. Shorter exposure periods can provide some information, but accurate pitting rate or mass-loss determinations may require exposure of six months or more.

3.6.1.2 Test nipples should be cleaned and accurately weighed prior to and after exposure to allow calculation of corrosion rate during the exposure period.

3.6.1.3 Mass loss 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.

3.6.1.4 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.

3.6.1.5 Test nipples/spools should be cleaned, and volume, mass, or wall thickness measurements accurately determined prior to and after exposure to allow calculations of corrosion rate during the exposure period.

3.6.2 Electronic Devices.¹⁵⁻¹⁷ 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 1.3.

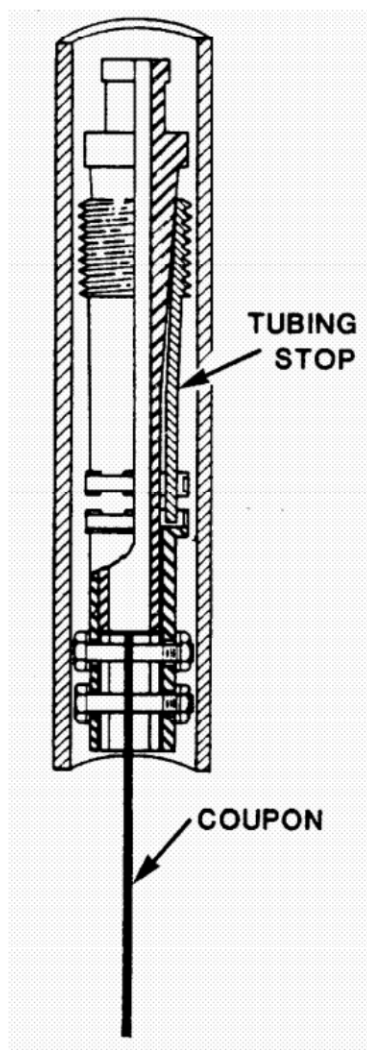


FIGURE 7: Wire-line-operated tubing stop adapted as downhole coupon holder.

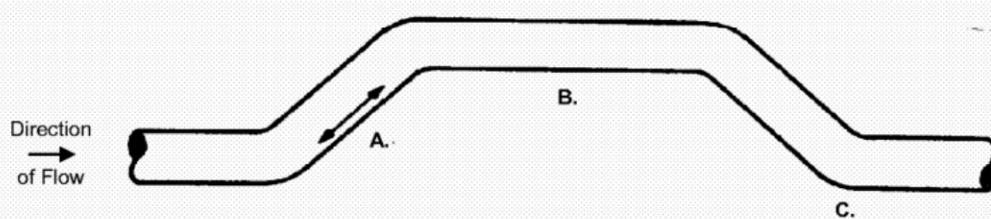


FIGURE 8A: With Low Flowrate (Below Limiting Velocity)*

- 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.

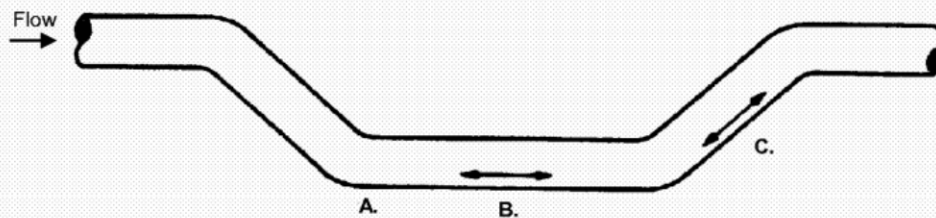


FIGURE 8B: Low Flow Rate

Corrosion most severe at B and C.

HIGH FLOW RATES

Corrosion most severe at A.

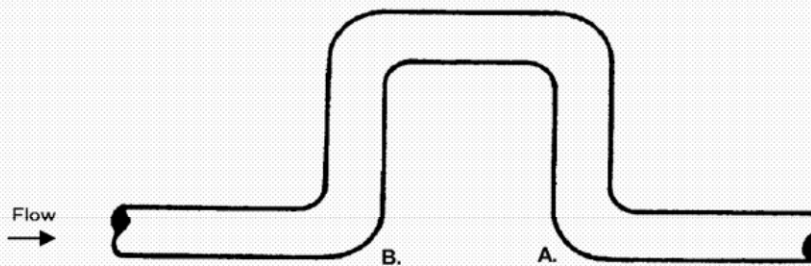


FIGURE 8C: Vertical Riser in Gas Line Carrying Small Volume of Water

- 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 8: 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.

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 Data from corrosion coupons and other monitoring instruments seldom correlate exactly with the rate of corrosion observed in the system. Factors that can contribute to the lack of correlation include coupon location and multiphase flow characteristics. Coupons installed in a single-phase system, such as a water injection line, correlate with corrosion rates on system components better than coupons in three-phase systems of oil, water, and gas. In stratified multiphase systems, attack may be confined to the part of the coupon exposed to the corrosive phase. Coupons provide valuable information for long-term exposures. Intermittent conditions 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. Banded coupons can 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). Coupon data reflect only the average rate of corrosion during the test period.¹⁶ Major changes such as the initiation of an effective mitigation program may be evaluated with corrosion coupons. Coupons can be useful in providing back up for other types of corrosion monitors.¹⁵⁻¹⁸ Coupon data should be correlated also with the corrosion failure frequency in the system being studied.

5.2 Continuous monitoring is essential so that changes in the corrosion rate in a system may be detected as soon as possible after they occur. This permits early mitigation, which can prevent dangerous and expensive equipment failures.

5.3 Qualitative guidelines for interpretation of measured corrosion and pitting rates are given in Table 2. The average corrosion and pitting rates shown in Table 2 are intended for use only as guides. The table was compiled from information on carbon steel systems. Common sense

must be exercised in the evaluation of corrosion rates as shown by corrosion coupons. Coupons installed in dynamic systems may indicate a higher rate of corrosion than is actually occurring on the interior wall of the system piping. Conventional coupons protrude into the flow stream and are thus subject to more turbulence than the pipe wall. Also, coupons are initially clean and free of protective films that may be providing considerable protection to the pipe wall. The rate of corrosion of a coupon may 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 rate of corrosion. In other systems, corrosion rates may increase with longer exposure time. Pitting sometimes begins only after an "incubation period." Underdeposit corrosion usually becomes severe only after the coupon is exposed long enough for deposits to form. A coupon made of a corrosion-resistant metal may be exposed adjacent to the coupon under test to assess the effects of mechanical erosion.

5.3.1 Use of guidelines in Table 2 must be tempered by 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.

5.3.2 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. 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.

Table 2: Qualitative Categorization of Carbon Steel Corrosion Rates for Oil Production Systems

	Average Corrosion Rate		Maximum Pitting Rate (See Paragraph 2.5)	
	mm/y ^(A)	mpy ^(B)	mm/y	mpy
Low	<0.025	<1.0	<0.13	<5.0
Moderate	0.025-0.12	1.0-4.9	0.13-0.20	5.0-7.9
High	0.13-0.25	5.0-10	0.21-0.38	8.0-15
Severe	>0.25	>10	>0.38	>15

^(A) mm/y = millimeters per year

^(B) mpy = mils per year

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Appendix A—Typical Corrosion Coupon Report

Lease or facility _____ Well number _____

Well or facility type _____

Flowrates—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 position shown: _____

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 _____