

From the desk of G. A. Aaker, Jr., PE.

TYPICAL OIL FIELD CORROSION TYPES

Internal Corrosion

The occurrence and rate of internal corrosion is governed by a variety of process conditions which include:

- Corrosivity of the fluid, in particular due to the presence of water combined with hydrogen sulfide, carbon dioxide, or oxygen. Temperature and pressure can have a great impact on the corrosion rates.
- Velocity of the fluid, which determines the flow regime in the pipeline. In pipelines transporting fluids containing water, too low velocities lead to settlement of water, which may lead to bottom of pipe internal corrosion; too high velocities can increase the overall corrosion rate and also destroy the protective scale or inhibitor films
- Deposition of solids, which may prevent adequate protection by inhibitors, and can create anaerobic conditions for the growth of SRB.

CO₂ CORROSION

Carbon dioxide gas (CO₂), when dissolved in water, forms carbonic acid (H₂CO₃). This acid may attack metallic equipment, in particular carbon steels and low-alloy steels. Wet CO₂ corrosion can be relatively uniform (i.e., general corrosion), but more often occurs in the form of pitting, grooving, or the so-called "mesa attack" (protected, scale-covered area co-exists with corroded areas of fresh metal).

The main influencing factors in wet CO₂ corrosion are CO₂ partial pressure, temperature, pH (impacted by the presence of organic acids), flow velocity, and dissolved iron concentration. The partial pressure of CO₂ can be used to predict corrosiveness of gas condensate wells. A partial pressure above 30 psi usually indicates corrosion; a partial pressure between 3-30 psi may indicate corrosion; and a partial pressure below 3 psi generally is considered non corrosive. Organic acid salts have been detected in the production fluids and can enhance the CO₂ corrosion. A lower pH or higher CO₂ partial pressure will cause a higher corrosion rate. A higher temperature usually means a higher corrosion rate. However, at temperatures above 80 °C (176 °F), a layer of scale (iron carbonate, FeCO₃) may form and is capable of protecting the steel from further rapid attack, provided that the scale is not damaged. Wet

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CO₂ corrosion under scaling conditions is particularly sensitive to flow velocity, as high flow velocity or turbulence may damage the FeCO₃ scale and prevent it from re-forming. High CO₂ corrosion dominates during the early phase of the well production (high pressure, high flow rates) and the flow regime is slug or annular. As the flow regime moves toward stratified flow, CO₂ corrosion will become less important.

When both CO₂ and H₂S are present, the governing corrosion mechanism depends on the ratio of their partial pressures.

CO ₂ /H ₂ S < 20	H ₂ S corrosion dominates
20 < CO ₂ /H ₂ S < 500	Mixed CO ₂ /H ₂ S corrosion
CO ₂ /H ₂ S > 500	CO ₂ corrosion dominates

In general, the corrosion rate of mixed CO₂/H₂S corrosion is less than that of CO₂ corrosion. Therefore it is a conservative approach to treat mixed CO₂/H₂S corrosion and CO₂ corrosion in the same way.

In case of H₂S corrosion, iron sulfide (FeS) forms a protective layer over the steel. However this quickly breaks down in the presence of chloride salts and oxygen with severe pitting occurring at breaks in the FeS layer. The pits are usually shallow and rounded with sloped edges (conical shape). The hydrogen atoms produced from the reaction of H₂S and iron may combine and form hydrogen gas that may bubble harmlessly off the steel surface or diffuse into the steel and cause Hydrogen Induced Cracking (HIC) or Sulfide Stress Cracking (SSC), a great concern than corrosion.

OXYGEN CORROSION

Oxygen corrosion is common in produced water systems due to the lack of gas blankets on tanks and trucking of produced water. Oxygen corrosion is particularly severe with high corrosion rates and characterized by deep pits and localized corrosion. When H₂S is present, H₂S and O₂ would cause incremental corrosion rate impact.

There is no practical means to mitigate oxygen corrosion except excluding oxygen (<20 ppb) and/or material selection.

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MICROBIOLOGICALLY INDUCED CORROSION (MIC)

MIC is caused primarily by Sulfate Reducing Bacteria (SRB) and also Acid Producing Bacteria (APB) that grow in presence of nutrients (nitrogen, phosphorous, sulfate). SRB reduce sulfate to hydrogen sulfide that reacts with carbon steel to produce iron sulfide as corrosion products. Aerobic bacteria near the outer surface of the biofilm consume oxygen and create a suitable habitat for the SRB at the metal surface. SRB can grow in stagnant water or slow flow locations. Symptoms of SRB-influenced corrosion are hydrogen sulfide odor, blackening of water, and black deposit (iron sulfide).

As the flow regime moves toward stratified flow, MIC tends to dominate, especially at the low points in the system.

EROSION CORROSION

Erosion corrosion is the accelerated mechanical removal/corrosion as a result of relative movement between the solids, liquids or vapors, or any combination thereof and the material. The surface material removal can be just mechanical or in combination with corrosion, especially with CO₂ corrosion. Erosion by sand is a known issue in high rate wells and flow lines. Production and inspection plans must be developed with erosion in mind. Refer to sand management plan for each asset.

UNDER-DEPOSIT CORROSION

Under-deposit corrosion is a form of localized corrosion. Concentration cell corrosion, crevice corrosion and gasket corrosion are all forms of under-deposit corrosion. This is an aqueous form of corrosion; therefore it can occur any place that liquid water forms. Examples of deposits which may produce under-deposit corrosion include sand, dirt, corrosion products, biofilms, and other solids.

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Under-deposit corrosion occurs when two or more areas of the same metal surface (electrodes) are in contact with a solution (electrolyte) differing in concentration of one of the reactants between the two metal areas. A difference in the concentration leads to a difference in electrochemical potential (electromotive force), which is the driving force for corrosion to occur. The difference in potential also leads to the formation of discrete anodic and cathodic sites. When there is an electrolyte and a metallic path for the current, the circuit is complete, current flows, and electrochemical corrosion will occur. Shielded areas, i.e. under deposits, gasket surfaces, or within crevices, are often anodic to the surfaces exposed to the bulk solution.

External Corrosion

CORROSION UNDER INSULATION (CUI)

Much of the flow line and process piping at the well pads are insulated to avoid hydrate formation. Water entering external insulation may collect at low spots/insulation support rings and cause severe (localized) corrosion of carbon steel. This especially holds for insulated equipment operating in the temperature range of 80-120 C. Water entering through coating defects and poorly applied joint sleeves can cause severe (localized) corrosion of carbon steel. This problem is related to the type of insulation and quality of installation. Future inspection and mitigation are expected.

SOIL CORROSION

The deterioration of metals (carbon steel, cast iron and ductile iron) exposed to soils is referred to as soil corrosion. Underground pipelines, piping and equipment as well as buried tanks and the bottoms of above ground storage tanks are susceptible to soil corrosion.

The severity of soil corrosion is determined by many factors including operating temperature, moisture and oxygen availability, soil resistivity (soil condition and characteristics), soil type (water drainage), and homogeneity (variation in soil type), cathodic protection, stray current drainage, coating type, age, and condition. Soil resistivity is frequently used to estimate soil corrosivity, mainly because it is easy to measure. Soils having high moisture content, high dissolved salt concentrations, and high acidity are usually the most corrosive. Corrosion rates increase with increasing metal temperature. Other

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factors that affect soil corrosion include galvanic corrosion, dissimilar soils, stray currents, differential aeration corrosion cells, and MIC.

Soil-to-air interface areas are often much more susceptible to corrosion than the rest of the structure because of moisture and oxygen availability. For underground piping and pipelines where the lines are insulated with coatings, air to soil interface can be an issue where the end of the coatings are not sealed sufficiently to prevent water/moisture ingress, corrosion can be severe. The facilities near the flooding zone of the river, e.g. the surface casing at the bottom of well head, can suffer more from this air-soil corrosion.

Soil corrosion appears as external thinning with localized losses due to pitting. Soil corrosion of carbon steel can be minimized through the use of special backfill, coatings and cathodic protection. The most effective protection is a combination of a corrosion resistant coating and a cathodic protection system. The most common method used for monitoring underground structures is measuring the structure to soil potential using dedicated reference electrodes near the structure (corrected for IR drop error).

Other

SULFIDE STRESS CRACKING (SSC)

SSC is a form of [Hydrogen Stress Cracking \(HSC\)](#). It is an environmental cracking mechanism that can initiate on the surface of high strength alloy steels or carbon steels containing localized areas of high hardness/stress. The cracking from SSC is the result of atomic hydrogen diffusion into the steel causing Embrittlement. Atomic hydrogen is generated as the cathodic product by the corrosion reaction of wet H₂S with the steel.

The likelihood of SSC occurring is related to the susceptibility of the material and the degree of hydrogen charging in the metal. The susceptibility of the material is dictated mainly by strength level or hardness, and the level of applied stress. High strength alloy steels (tensile strength > 620Mpa) are considered to be susceptible. Carbon steel and low strength alloy steels are generally not considered to be susceptible. However, weld deposits and HAZs may contain local areas of high hardness and/or high residual stresses from the manufacturing process (e.g. welding or cold forming) that can result in increased susceptibility to SSC in low

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strength steels. The degree of hydrogen charging in wet H₂S service is in turn related to pH and the concentrations of both sulfide and cyanide in the water.

Selection of resistant materials is the best approach for prevention of SSC and will be dependent on the material, its properties and heat treatment. An alternative approach to mitigation is to prevent or reduce the degree of hydrogen charging. The application of corrosion resistant linings, either metals or paints/coatings will prevent the aqueous corrosion reactions that are responsible for the production of atomic hydrogen and therefore SSC.

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HYDROGEN INDUCED CRACKING (HIC)

Hydrogen blistering, HIC and Stress Oriented Hydrogen Induced Cracking (SOHIC) are all degradation mechanisms associated with the formation of hydrogen blisters in the metal that occur when it is charged with atomic hydrogen produced by aqueous corrosion of the metal surface. These hydrogen-charging conditions are commonly produced by corrosion in the presence of water and hydrogen sulphide (H_2S). The H_2S also serves as a poison to the recombination of atomic hydrogen to form molecular hydrogen gas (H_2), thus promoting entry of the atomic hydrogen into the metal.

As the atomic hydrogen diffuses through the metal, it tends to accumulate in internal laminations, non-metallic (e.g., sulphide and oxide) inclusions or other discontinuities in the metal, where it recombines to form molecular hydrogen gas. The gaseous hydrogen cannot escape from the metal by diffusion, so hydrogen pressure builds to extreme levels within the discontinuity and usually forms a subsurface planar cavity known as a hydrogen blister. Once hydrogen blisters form, HIC and SOHIC may develop as a result of the stresses present from the hydrogen pressure build-up in the blisters and from residual or applied stresses in the metal component.

HIC occurs as hydrogen pressure builds within hydrogen blisters, increasing stresses at the edges of the blisters and causing stepwise cracks to form that link adjacent hydrogen blisters on different planes in the metal, or to the surface of the metal. This cracking has sometimes been referred to as stepwise cracking because of the stair-step appearance of the cracking in photomicrographs. No externally applied stress is necessary for this cracking to occur.

SOHIC involves arrays of small hydrogen blisters that are stacked in a through-wall orientation and connected by HIC. The through-wall orientation of the cracking is the result of its nearly perpendicular alignment to high, localised tensile stress (residual or applied) in the plate. SOHIC usually occurs in the base metal adjacent to the weld Heat-Affected Zone (HAZ) where local stresses are highest due to the additive effect of residual stress from welding and the applied stress from internal pressure. SOHIC has also been found in other areas of high triaxial stresses, such as emanating from the tips of other cracks or defects (mechanical or environmental).

The sulphide concentration in the water is usually related to the H_2S partial pressure in the gas phase associated with the water. The likelihood of hydrogen blistering, HIC and SOHIC

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increases with increasing sulphide concentration in the water. At sulphide concentrations less than 50 ppm the likelihood of hydrogen blistering, HIC and SOHIC is considered to be low. At sulphide concentrations greater than 50 ppm the likelihood of hydrogen blistering, HIC and SOHIC is considered to be moderate. Presence of sulphide concentrations above 1,000 ppm and/or high levels of cyanides (>20 ppm) in the water at pH values above 7.5 further increase the hydrogen charging of the steel and can produce a high likelihood of blistering, HIC and SOHIC.

FATIGUE

Fatigue is a cracking mechanism that results from imposition of cyclic stresses that are lower than the normal tensile fracture stress. It includes mechanical fatigue, thermal fatigue and corrosion fatigue.

Mechanical fatigue occurs as a result of cyclic mechanical stresses that may be associated with pressure fluctuations in vessels or piping, rotational loads on a pump or compressor shaft, or high frequency vibration-induced dynamic loading. Small-bore connections, especially those with inadequately supported valves located near reciprocating pumps or compressors, are especially prone to vibration-induced fatigue. Mechanical fatigue problems are often associated with certain flow regimes in piping systems including slug flow, water hammer, vortex shedding and highly turbulent flashing conditions at and downstream of control valves or restriction orifices where a large pressure drop occurs.

Thermal fatigue is a type of fatigue that occurs as a result of cyclic thermal stresses. Whenever possible, the best method of eliminating thermal fatigue is to reduce the thermal gradients, and the magnitude or number of thermal cycles. Using thermal sleeves (insulating inserts) at nozzles and connections where interior thermal cycles are occurring have proven to mitigate thermal fatigue or at least extend the life of the component.

Corrosion fatigue is a form of fatigue in which cracking of the material occurs in the combined presence of a corrosive environment and cyclic loading. Corrosion fatigue can be often be addressed by proper materials selection, i.e., by using a more corrosion-resistant material for the service environment. Other methods used for the prevention of corrosion, such as painting, inhibitors, and cathodic protection are also relevant for the prevention of corrosion fatigue. Equally, those methods used to prevent mechanical fatigue and thermal

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fatigue, in combination with corrosion prevention methods, are suitable for mitigating corrosion fatigue.

BRITTLE FRACTURE

Brittle fracture is a rapid fracture that occurs with little or no plastic deformation. Generally, construction materials are ductile and undergo large deformation and/or some form of stable crack growth prior to failure. However, these materials may be exposed to service conditions that cause them to become brittle. When in a brittle condition, these materials can fracture in a sudden (without warning), unstable and often catastrophic manner with little or no deformation. Brittle fracture requires little energy and often results in fragmentation.

Most metals undergo a ductile-to-brittle transition in fracture toughness with decreasing temperature. For ferritic steel equipment built to modern standards (e.g., post 1989 ASME Boiler and Pressure Vessel Code, Section VIII, or equivalent), brittle fracture is generally not a primary concern for any MDMT above -7°C (20°F). This temperature can be as high as 49°C (120°F) for older carbon and low-alloy steels, and as high as 82°C (180°F) for carbon-0.5Mo steels. Fine-grained carbon steels with proven toughness by impact testing are applied down to about -46°C (-50°F) and possibly lower with additional requirements such as postweld heat treatment (PWHT) and thickness limitations. For even lower temperatures, nickel-containing low-alloy steels are applied, with 9%Ni steel being used at temperatures as low as -196°C (-320°F). Alternatively, austenitic stainless steels (i.e., 300 series) are used because they have no ductile-to-brittle transition when cooled. Some aluminum and nickel-based alloys are also used for low temperature service.

Welding procedures and filler metals are crucial in the prevention of brittle fracture because good toughness is more difficult to achieve for the deposited weld metal and adjacent Heat-Affected Zone (HAZ) than for base metal itself. Also, welds are likely locations for defects (e.g., porosity, lack of fusion, etc.) and are often located in areas of stress concentration.