

Corrosion Modeling: Influencing Factors

Corrosion modeling is a vital tool in the pre-Front End Engineering Design (FEED), FEED, and operational stages of the life of pipeline and flowline systems. Corrosion and materials engineers often rely on corrosion prediction models to select appropriate materials for construction, incorporate sufficient corrosion allowance into a design, and establish the need for chemical corrosion inhibitors or other corrosion mitigation methods. However, there are nuances in the way each corrosion model applies the input parameters to predict corrosion rates. Correct interpretation of corrosion model predictions requires an understanding of these nuances.

This GATEKEEPER will discuss the basic factors influencing corrosion modeling, while a later installment will elaborate on the different corrosion models available and their respective advantages and limitations.

The Corrosion Process & Influencing Factors

Corrosion occurs as a result of an electrochemical reaction between an anodic region and a cathodic region of a metal or alloy connected by both a metallic and electrolytic path. For instance, in offshore installations this means a pipe or structure in contact with water. Several factors affect the rate and extent of corrosion, including temperature, pressure, composition of the surrounding fluid, and physical characteristics of flow. How these factors affect corrosion, and thus corrosion model predictions, is detailed below.

Temperature & Pressure

Temperature and pressure can heavily influence the corrosion rate both directly, by speeding the corrosion process, and indirectly, by affecting scale formation, fluid flow, and the fugacity of gases present in the environment. It is imperative that these values are known or corrosion model use will be ineffective.

Usually, a temperature or pressure increase directly leads to a higher corrosion rate because electrochemical reactions generally occur faster at higher temperatures. Temperature increases add energy to the reactions, which increases the corrosion rate. Most corrosion models are accurate only within prescribed temperature ranges.

When corrosive gases such as CO₂ and H₂S are present, a rise in operating pressure can increase the partial pressure of these corrosive reactants. Corrosion models use fugacity of the gases in calculating corrosion rates. In fact, though corrosion rate can be effectively modeled using gas partial pressures, corrosion models typically use the fugacity of the corrosive gas instead. Fugacity is the quantity of active gas in solution. As for temperature and pressure, some models will have limits on the gas fugacity. The fugacity value is calculated by the model and is mostly based on pressure and gas mole percent. However, many models approach this calculation differently, so it is important to understand how the calculation is performed by each specific model as this will bring better insight into the interpretation of the final predicted corrosion rate.

Ionic Species

Certain models account for the effects of ionic species in the water or brine and allow the user to manually input and adjust the species' concentrations. Brine is composed of ionic compounds which are generally partially composed of products of gas-liquid reactions. For example, CO₂ reacts with water to form bicarbonates and carbonates.

Some models allow for the manual adjustment of concentrations of species such as bicarbonate and carbonate. Typically, this fluid is the produced fluid from the reservoir, but can also simply be condensed water that forms as gas streams cool. Condensed water is ion free and typically has a significantly lower pH than produced water due to its lack of CO₂ buffering capacity. If chemical analysis of produced fluid samples are available, it is advantageous to use the information in a more robust model that can handle many input parameters.

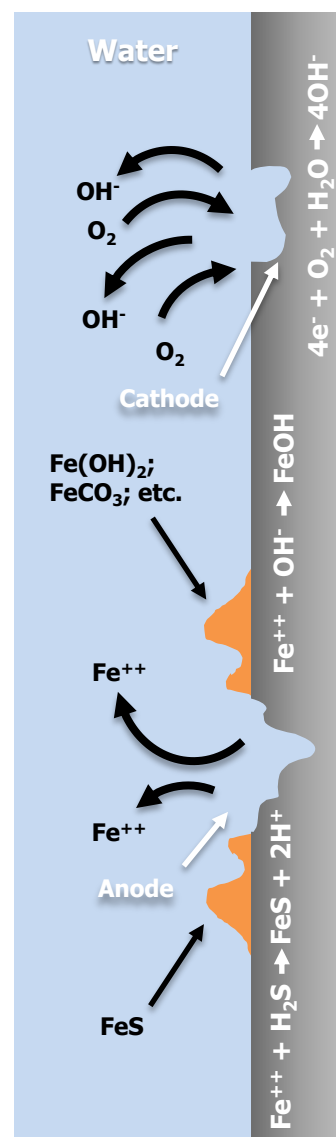


Figure 1: Iron Scale Formation Reactions

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Fluid samples will also allow for more accurate prediction of scale formation and pH values, both of which are significant influencing factors in corrosion modeling predictions.

A major consideration in corrosion modeling is organic acid. The effect of organic acids is most noticeable at higher temperatures and low pH. A major issue with many corrosion models is that they either ignore the presence of organic acids, which provides an under-prediction of corrosion rate, or they assume that all organics are present as acids rather than as salts, which massively over-predicts corrosion rates in systems with moderate to high natural pH values.

Thus, organic acid values will need to be included in the model to get a more accurate pH value in the pipe. Note that some models take direct account of the effect of organics acids on CO₂ while other models only account for it in pH calculations. Therefore, knowing the organic acid content in the formation and how it is used in the chosen model can be a critical aspect to interpreting model outputs.

pH Influence

The pH value can depend on several different parameters, such as temperature, pressure and the presence of carbonates and other ionic buffers. Condensed water will tend to be more acidic, while formation water will tend to have a higher pH due to the presence of buffering species, all of which can be incorporated into a corrosion model.

The level of sophistication for calculating the pH value varies widely from model to model. Some will include only effects from carbonate, while some will take water chemistry as an input and consider the presence of ionic buffers as well. Others will take H₂S into account only to calculate its effect on pH of the water in the pipeline, while ignoring its effect on the corrosion rate or scale formation. These different issues mean that sophistication of the model in calculating pH must be considered when interpreting model predictions. A more reliable value for pH can often be obtained empirically by testing the produced fluids, where the value obtained from the in-situ fluids can subsequently help guide the interpretation of corrosion modeling results.

Scale Formation

Scale is a layer of material that forms on a surface by precipitation or reaction of the surface with the environment. Typical scales include iron carbonate and iron sulfate, precipitated in the presence of CO₂ or H₂S, respectively. When it is possible for both scales to precipitate in the same system, formation of one will dominate over the other. The rule of thumb is that as long as the ratio of quantity of CO₂ to H₂S is greater than 500, CO₂ corrosion will dominate and iron carbonate scale will form. If the ratio is less than 20, H₂S is dominant and iron sulfate scale will form.

Any ratio falling between those two limits has behavior that can be difficult to predict. Figure 1 shows the reactions that would occur to create these two types of scales.

The way in which scaling is handled differs from model to model. Certain corrosion models incorporate scale, while others do not.

If scaling is expected, the model being used must be thoroughly understood to ensure realistic expectations from corrosion rate predictions. It is also helpful to have a separate scaling program and available produced fluids information to better model the chances of scale formation.

The combination of scale modeling and corrosion modeling programs can provide the clearest picture of potential corrosion and scaling issues.

Flow Regime

Flow regime describes the manner in which fluid flows through a pipeline. The type of flow regime depends on the superficial velocity of the gas and liquid phases, fluid properties, pipe roughness, and pipe geometry. The type of flow affects the shear stress imparted by a flowing fluid on a pipe wall. Most programs allow both the calculation of the shear stress and direct input of the shear stress. High fluid velocity at the pipe wall can lead to high shear stress, which can influence corrosion rates by affecting mass transfer rates of water and other species involved in corrosion reactions or scale formation.

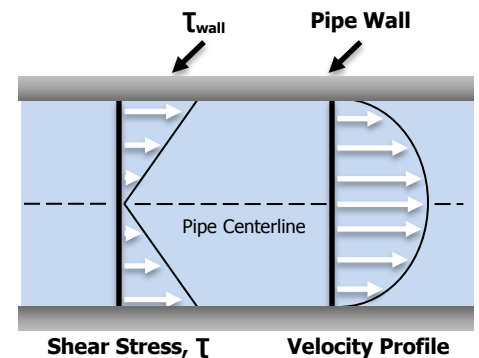
The effects of multiphase flow, where gas, oil, and water share the same flowline, is difficult to model. Knowledge of the flow regime is required to estimate the amount of water that contacts the surface of the pipeline and can be used to determine water wetting effects.

Water Wetting

The degree of water wetting of the pipeline surface is important to consider when calculating the overall corrosion rate because it signifies how much water is actually in contact with the pipeline surface. This is typically related to water cut, where some models assume no decrease in corrosion due to oil wetting, others assume it occurs at a fixed rate up to a threshold water cut, while others use a progressive increase in corrosion up to a set threshold. This can greatly impact modeled corrosion rates, particularly in early-life field scenarios.

Conclusion

Corrosion modeling can be an extremely useful tool in guiding the effective selection of materials or design of corrosion mitigation systems. However, differences between available corrosion prediction models can lead to a gradient of results. It is important for users to understand the parameters and design constraints behind each model in order to accurately assess the corrosion modeling results before making recommendations.



Shear Stress & Velocity Profiles in a Pipe

Velocity and shear stress are related relative to the pipe. Different models may use different calculation methods and it is important to know which method is being used to ensure accurate interpretation of model results.



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