Top of Line Corrosion Part 1: Determining Risk

Top of line corrosion primarily occurs in wet gas systems when water vapor condenses on the internal walls of the pipeline due to the heat exchange occurring between the pipe wall and the colder ambient medium. As the liquid condenses on the internal pipe wall, the concentration of the acid gases and organic acids (naturally present in the gas stream) in the liquid increases. Thereby the pH value of the condensed water drops turning the water corrosive. The corrosion caused by such acidic, corrosive condensed water on inner wall of the upper half of the pipeline is called top of line corrosion (TOLC). Absence of bicarbonate or iron in the condensed water keeps the pH value low. While CO_2 is the predominant gas of concern, H_2S can also present significant challenges. The key factors influencing TOLC are listed in Figure 1.

The condensed water subsequently becomes saturated with dissolved iron from the corrosion process, resulting in an increase in pH and the stabilization of a semi-protective corrosion product layer. As the acidity level of the already condensed water drops due to the dissolution of iron, the TOLC rate then becomes dependent on the water condensation rate and the amount of iron which can be dissolved in the newly condensing water. The amount of iron in the condensed water increases as the pipe gets corroded and decreases as more water condenses. The net TOLC rate depends on the balance between these counteracting effects. This behavior results in a critical rate of condensation below which corrosion is not anticipated. The critical rates of condensation from experimentation results are shown in Figure 2.

Where Does Top Of Line Corrosion Occur?

TOLC occurs in gas production and export lines with stratified flow as the water condensation occurs in the upper part of the line where corrosion inhibitors or other corrosion protection chemicals such as MEG are not reliably transported. TOLC can also occur in both subsea and surface piping wherein the ambient temperature is significantly lower than the pipeline fluid temperature.

How to Determine Top Of Line Corrosion Risk?

The water chemistry in the thin film of condensed water in the top of the pipeline can be very different from the bulk water phase in the bottom of the line. The condensation of water as discrete drops, rather than a phase, also impacts corrosion dynamics. This has led to the development of a series of guidelines to correlate bottom of the line corrosion (BOLC) rates to TOLC rates.

Several TOLC models have also been developed to calculate TOLC rate from the water condensation rate and the concentration of iron in the condensed water for sweet (little or no H_2S) systems. For systems with even small amounts of H_2S, TOLC models are not directly applicable as corrosion product layer will be dominated by iron sulfide instead of iron carbonate. The mechanisms for supersaturation and protective film formation for iron carbonate-dominated systems are very different from those with a significant H_2S fraction, making the corrosion prediction a very challenging process.

Evaluating the Top Of Line Corrosion Risk

Evaluation of the TOLC risk involves the following steps [4]:

1. Input Data Review
2. Modeling & Analysis
3. Study of Key Parameters
4. Calculation of BOLC Rate
5. Calculation of TOLC Rate
6. TOLC Risk Assessment

Input Data Review, Modeling & Analysis

Field layout and bathymetry, pipeline geometry with insulation and coatings, pipeline burial conditions, ambient temperatures, concentrations of CO_2, H_2S, organic acids, and dissolved solids are reviewed to assess the corrosion risk at a high level prior to modeling.

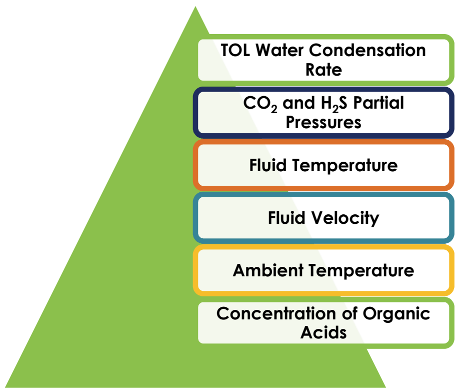

Figure 1: Factors Influencing TOLC

Dugstad et al [1]	• 0.51 ml/m²s at 85°C (185°F) • 0.28 ml/m²s at 65°C (149°F) • 0.03 ml/m²s at 30°C (86°F)
Singer et al [2]	• 0.25 ml/m²s • 0.025 ml/m²s (if large quantities or organic acids are present)
Gunaltun et al [3]	• 0.15 to 0.25 ml/m²s (Wet gas lines)

Figure 2: Critical Top of Line Water Condensation Rates

BOLC Models

- De Waard 95
- NORSOK M506
- NORSOK Modified (GATE)

TOLC Models

- IFE Model
- NORSOK Modified (GATE)

Figure 3: BOL and TOL Corrosion Models

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The flow system is modeled in entirety and thermo-hydraulic analysis of the flow through the system is performed at steady state and transient conditions.

Study of Key Parameters

From the analysis results, key parameters like flow regime, top of line water condensation rate, pH value of flow in the system, partial pressure of CO_2, liquid holdup, JT cooling across the subsea choke, warmup times in case of cold restart, etc., are studied in detail.

Calculation of BOLC Rate & TOLC Rate

Methodologies used to assess TOLC risk across the oil and gas industry are either based on heuristics linking, such as critical condensation rates or the BOLC rate, or analytical models based on laboratory experiments and field observations, such as the Institute for Energy Technology (IFE) corrosion model.

Some of the commonly used corrosion models are listed in Figure 3. While De Waard 95 and NORSOK M506 models are used to predict BOLC rates, the IFE model is used to predict TOLC rate. GATE uses modified NORSOK M506 model to predict BOLC and TOLC rates.

Determining TOLC: Modified NORSOK M506 Model

One of the limitations of the NORSOK M506 model is that it is not very accurate at increasingly high levels of acetic acid in the produced fluid.

Modifed NORSOK modeling involves calculation of the pH value of the condensing water using the ScaleChem software. The calculated pH value is then input to the NORSOK M506 model to accommodate for the limitations of the NORSOK M506 model and the BOLC rate is calculated.

$$\boldsymbol{CR = f(pH, T) \times g(T) \times h(PCO_2, \tau)}$$

Where $\boldsymbol{CR}$ is the BOLC rate, $\boldsymbol{pH}$ is the hydrogen potential, $\boldsymbol{T}$ is the Fluid Temperature, $\boldsymbol{PCO_2}$ is the CO_2 Partial Pressure and "τ" is the wall shear stress.

Though both of these models lose accuracy as levels of organic acid increase, the use of specialized water chemistry software to estimate the pH of the condensing water and the solubility of iron carbonate under top of the line conditions can help accommodate for their limitations in this regard.

de Waard introduced a correcting factor of 0.1 to adapt BOLC model calculation outputs to TOLC when top of line water condensation rates are above the experimentally determined critical rate of 0.25 ml/m²s. This is known to provide a conservative prediction of TOLC rates compared to other more rigorous evaluations, but has been widely adopted by the oil and gas industry [3].

By applying a correction factor of 0.1 to the BOLC rate calculated in previous step, the TOLC rate is calculated: $\boldsymbol{TOLC = 0.1 \times BOLC}$

Determining TOLC: IFE Corrosion Model

The TOLC model developed by IFE is based on experimental data obtained from direct measurement of corrosion and water condensation rates produced by a fluid containing CO_2 and wet gas in a closed pipe system.

These experiments have shown that the TOLC rate caused by the CO_2 in the system is limited by the water condensation rate and the amount of iron which can be dissolved in the condensed water. The basic model is described by the following expression:

$$\boldsymbol{CR = 0.004 \times R_{cond} \times C_{Fe} \times (12.5 - 0.09T)}$$

Where $\boldsymbol{CR}$ is the TOLC rate in mm/y, $\boldsymbol{R_{cond}}$ is the water condensation rate in g/m²s, $\boldsymbol{C_{Fe}}$ is the solubility of iron in ppm (wt) in the condensed water and $\boldsymbol{T}$ is the temperature of the fluid in °C. To apply this model, it is necessary to estimate the water condensation rate at a given temperature, the total pressure, the CO_2 partial pressure and the glycol concentration. These are usually obtained by the usage of a fluid characterization / thermal-hydraulic simulation package. Other models are available and are based on proprietary data and specific for certain fields/compositions.

The conservative results obtained by the indirect method can be substantial, as illustrated Figure 4. Where a system is always above an established corrosion limit of 0.1 mm/yr via the indirect method, the direct method indicates the system is above the corrosion limit only for the first 1,200 meters.

TOLC Risk Assessment

Based on the TOLC rate calculated from the previous step, along with the top of the line water condensation rate, TOLC risk is assessed and the locations in the system with TOLC are identified. We will discuss the assessment of TOLC risks and mitigation options more in Part 2 of this GATEKEEPER.

Conclusion

Flow assurance studies are often accompanied by a thorough evaluation of the corrosion risk for production and export facilities. However, every field is different and offers unique challenges depending on the geographical location, produced fluid composition and more. Using heuristic methods such as BOLC assessment to determine TOLC risk yields extremely conservative results, negatively impacting project CAPEX.

A systematic approach to the evaluation of TOLC risk helps in making changes to the field architecture in the early stages of a project and allow the adoption of suitable mitigation and control measures. This helps in optimizing the service life of infrastructure and minimizing both CAPEX and OPEX.

In Part 2 of this GATEKEEPER series, we will look at the different approaches available to assess risk in the system and will discuss the mitigation options available to us.

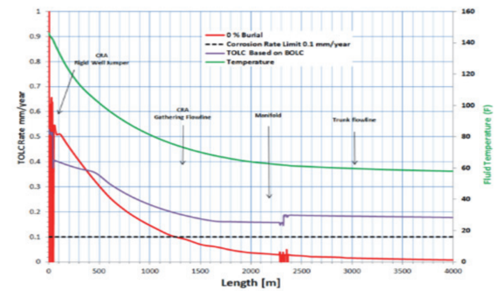

Figure 4: TOLC Rate Comparison for the Modified Norsok (Purple) and IFE (Red) Methods

References

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