

Avoiding Common Pitfalls in CO₂ Corrosion Rate Assessment for Upstream Hydrocarbon Industries

Seyed Mohammad Kazem HOSSEINI

ABSTRACT

Prediction of CO₂ corrosion rate is often regarded as the backbone of material selection process in upstream hydrocarbon industry. Several corrosion models have been developed since 1970s in order to assist material engineers in achievement of a robust assessment on the corrosivity of service fluids. However, the results obtained by various corrosion models for the same case may significantly vary due to software limitations or human factors or combination of both. In the present study, a survey was conducted on 15 offshore oil and gas projects in order to assess the accuracy of the predicted CO₂ corrosion rates. It was observed that the majority of reports contain a number of errors which could have been readily avoided if they were known by the user of corrosion models. The errors are classified into the following four main types: (1) using inadequate or false data as the input to the model, (2) failing to address factors which may have significant influence on corrosion rate, (3) utilizing corrosion models beyond their validity range and (4) utilizing a corrosion model for a specific set of input, where the model is considered to be inaccurate even though the input lies within the software's range of validity. To avoid the above-mentioned errors, some recommendations were made on how to choose a right corrosion model, how to properly use it and how to verify the output of corrosion rate assessment.

Keywords: *CO₂ corrosion rate, corrosion models, hydrocarbon industry, human errors*

INTRODUCTION

Corrosion is regarded as the main integrity threat to the assets in oil and gas industry. In order to mitigate corrosion, it is vital to conduct a corrosion study during the engineering phase of projects in which the following issues should be primarily addressed: potential corrosion threats, corrosion rate assessment, materials selection and development a corrosion control philosophy. The latter which includes proposed corrosion mitigation and monitoring programs will be implemented later on during asset operation through establishing a corrosion management strategy/system.

Selection of materials should be based on minimum life-cycle cost (i.e. minimum CAPEX+OPEX), provided that the proposed material can deliver adequate performance for the entire length of intended design life. A poor corrosion study with a very conservative and overestimating corrosion rate assessment may lead to imposing unnecessary cost to the project due to selecting a costly corrosion resistant material where a cheaper carbon steel material can also be used successfully. The impact of such assessment on the overall project cost can be explored by considering the fact that procurement cost constitutes about 50%-60% of an EPC contract in oil and gas sector. Procurement cost refers to the cost of equipment, service and bulk material, out of which the cost of material alone represents about 30% of total project cost, although these figures vary by complexity and type of project. Nevertheless, it is generally accepted that the cost impact of taking a conservative approach in corrosion rate assessment on the capital project cost is significant.

A poor corrosion study with underestimating corrosion rate assessment, on the other hand, encounters the assets to the immediate corrosion problems post-commissioning and therefore will necessitate a bigger, more holistic and more complicated corrosion management system post-commissioning [1, 2]. Implementing of such exhaustive system during operation is costly and will impose frequent shutdown for plant inspection which in fact increases the operational cost (OPEX).

Several corrosion models have been developed by oil companies and research institutes in order to assist engineers to have a more accurate assessment on the severity of CO₂ corrosion rate in hydrocarbon extraction and production industry. However, very different results can be obtained when the models are run for the same cases due to the different philosophies used in the development of the models [3]. The results of three Joint Industry Projects (JIP), which have been carried out in an attempt to collect the field data and reviews the performance of a representative group of models, have indicated that most of the models predict well the

“worst case” CO₂ corrosion rate but vary widely when more complex effects (e.g. protective films, water entrainment/wetting, H₂S, etc) are included. The main reason for this spread lies in the arbitrary nature of the empirical correction factors that are employed to account for the various complicating effects [4].

In addition to the uncertainties caused by the corrosion models, the human errors are also found to be the source of many false predictions exacerbating the unreliability of CO₂ corrosion rate assessment and, hence, suitability of the proposed materials. While the former type of uncertainties is being known somewhat of an inevitable in nature, the latter can be avoided if they are identified to the user of corrosion models. The present study is, thus, aims to identify the common errors in CO₂ corrosion rate assessments which can be found in a project document commonly known as “corrosion study and materials selection reports” and to recommend some precautionary measures in order to avoid them.

METHODOLOGY

In the present research, a number of corrosion study and material selection reports which have been conducted since 2005 in different offshore hydrocarbon projects (topside platform or subsea pipeline) were selected for the purpose of survey. The projects under study were based in three different geographical locations: North Sea, South East Asia and Middle East. To validate the predicted corrosion rates, various industry-accepted corrosion models were used: De Waard- Milliams (DM), Norsok M506 (NO), BP Cassandra 98 (CA), Intetech ECE5.0 (ECE) and Honeywell Predict 6.0 (PE). Process data were taken from basis of design, flow assurance, environmental data, heat and mass balance and other related project documents. The corrosion study reports were analyzed with regards to the suitability of CO₂ corrosion model used for the range of existing service conditions in a specific project, validity of assumptions made, adequacy and/or accuracy of input data and identifying any important factor which had not been taken into account in the assessment. Errors captured in the reports were categorized based on their type and nature.

RESULTS AND DISCUSSION

Table 1 summarizes the type of the errors which have been observed in fifteen different projects and indicates what corrosion model was initially used in the project for conducting corrosion study and materials selection.

Table 1 Summary of the survey on the corrosion rate assessment conducted in various upstream hydrocarbon projects.

	Location	Asset type	Corrosion Model	Type of error identified			
				Type 1	Type 2	Type 3	Type 4
Project 1	North Sea	Topside	NO	√	√	√	
Project 2		Pipeline	ECE				
Project 3		Pipeline	NO	√			√
Project 4		Pipeline	CA		√		√
Project 5		Topside	DM	√	√		
Project 6	South East Asia	Topside	DM	√		√	
Project 7		Topside	ECE		√		√
Project 8		Pipeline	NO	√			
Project 9	Middle East	Pipeline	PE		√	√	
Project 10		Topside	DM	√		√	
Project 11		Topside	DM	√	√		√
Project 12		Topside	NO	√	√		√
Project 13		Topside	NO			√	
Project 14		Topside	DM	√	√		√
Project 15		Pipeline	DM	√	√	√	

The abbreviations in the fourth column of the table are defined as follows:

NO: Norsok M506 corrosion model developed by Norwegian oil companies Statoil, Norsk Hydro and Saga Petroleum.

ECE: Electronic Corrosion Engineer model developed by Intetech Limited

CA: Cassandra corrosion model developed by British Petroleum

DM: de Waard-Milliams corrosion model developed by Shell

PE: Predict corrosion model developed by Honeywell Process Simulation

As demonstrated in table 1, there are four types of errors in CO₂ corrosion assessment found in the projects which were studied. These are explained in detail as follows.

Type 1 error occurs when false data is given to the corrosion model as the input data or when the assumption made to conduct the corrosion rate assessment is not valid for the specific service conditions existing in a project. Common examples of type 1 errors are included but not limited to the following:

- Considering concentration of CO_2 and H_2S in the mixture rather than their contents either in liquid (ppm) or in the gas phase for a multiphase fluid. For the single phase liquid flow, where there is no gas present at the particular point, the CO_2 content of the gas phase that the liquid was last in contact with should be used. For example, the separator gas in the case of a produced water outlet piping or a crude oil export line. For a downhole liquid the % CO_2 in the gas formed at the bubble point should be considered. If the gas analysis is not available, the amount of CO_2 dissolved in the brine, the Henry's constant, and the bubble point pressure can be used to back-calculated the effective % CO_2 which would be required in the bubble point of gas in order to sustain the known level of dissolved CO_2 . Fig. 1 illustrates schematic diagram of an oil production system in which the correct amount of pressure and concentration of CO_2 for corrosion rate calculation are indicated.

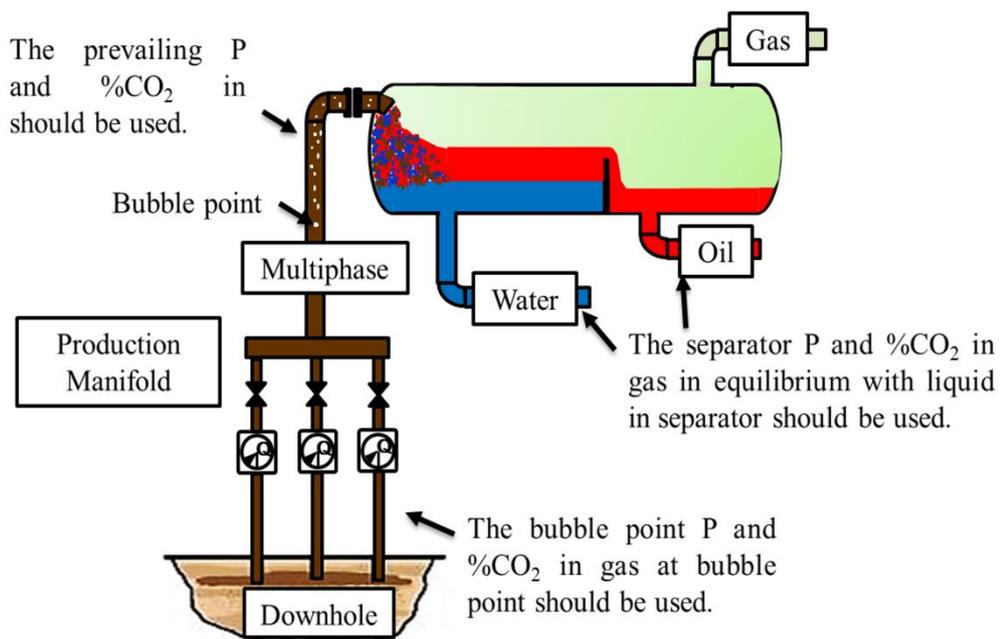


Figure 1 Schematic representation of typical oil and gas production system in which the correct amount of pressure and % CO_2 for corrosion rate calculation are indicated.

- The assumption of 0.1 mm/year residual corrosion rate for calculation of corrosion rate by using equation (1) for applications where such a target is not practicably attainable due to either high amount of uninhibited corrosion rate or presence of conditions in which the efficiency of corrosion inhibitor is anticipated to be low. For instance, the presence of slug flow with high frequency at pipeline reduces the efficiency of corrosion inhibitor due to increasing the amount of shear stress at the metal/liquid interface and accelerating mass transfer. For these conditions, the assumption of 0.1mm/year residual corrosion rate for the inhibited corrosion rate is not valid and the latter has to be calculated based on equation (2).

$$CR = CR_{inh} \times CIA + [CR_{uninh.} \times (1 - CIA)] \quad (1)$$

$$CR_{inh} = CR_{uninh} \times (100 - CIE)/100 \quad (2)$$

Where CR_{inh} and CR_{uninh} and CR are inhibited, uninhibited and resulted corrosion rates, respectively. CIA and CIE also denote the corrosion inhibitor availability and efficiency. Therefore, it is always recommended to check the inhibitor effectiveness for a given application before making any assumption on the amount of residual corrosion rate or corrosion inhibitor efficiency. A reliable approach to estimate inhibitor effectiveness is calculation of Inhibitor Likelihood Success Score (ILSS) based on the equation (3) derived after a Joint Industry project (JIP) conducted by BP Exploration, Intertek CAPCIS and DNV [5]. A high score would indicate that chemical corrosion inhibition would be unlikely to be successful without the use of very high concentrations. The inhibition risk can be classified based on ILSS factor as follows: A small ILSS less than 2.5 indicates that it is highly likely that corrosion inhibition is successful. A value of ILSS between 2.5 and 4 indicates that corrosion inhibition is expected to be successful. A value between 4 and 5.5 indicates corrosion inhibition will be challenging and finally a value greater than 5.5 implies to the fact that inhibition may not be viable. Therefore, for the first and second classes, higher corrosion inhibitor efficiency is anticipated while for the third class a reduced value in the range of 50-75% is recommended for corrosion rate calculation. For the fourth class, using corrosion resistant alloy is very likely to be the most reliable option.

$$ILSS = \frac{Temp (^{\circ}C)}{40} + \frac{Shear\ Stress\ (Pa)}{240} + \frac{TDS\ (mg/L)}{125000} + \frac{Pred_CR\ (mm/y)}{10} \quad (3)$$

Where TDS is Total Dissolved Solids expressed in mg/L.

- Calculation of ionic strength and pH based on the chemistry of formation water where the produced water contains considerable amount of condensed water. It is

noteworthy to mention that produced water is any water that is produced to the surface from an oil or gas reservoir along with the oil and gas. This water will be from one or more of the following sources: connate water present in the reservoir prior to production, condensed water which is condensed out of the produced gas in the production tubing, pipeline and topsides equipment, and injected water which has broken through from the injection wells to the producers.

- Considering a protective nature for corrosion products (i.e. $F_{scale} < 1$), where $CO_2/H_2S < 200$ and the service conditions are not in favor of formation of a stable iron sulfide film (e.g. presence of chloride, low pH, erosive flow, oxygen ingress, etc.) [6].
- Undertaking corrosion rate assessment based on the service conditions for the early production years. Although for the most cases this practice will deliver a prediction for the worst-case scenario, but this is not always true due to changes in well fluid composition at some points later on which will exacerbate the corrosivity of fluid. For instance, some wells may produce water-free hydrocarbon at early production stages though the water-cut increases gradually over the time.

Type 2 error occurs when a parameter or a factor which can have a significant influence on the corrosion rate has not been taken into account. Common examples of these parameters which are identified in this survey are listed as below.

- Flow regime and the hydrodynamics properties of fluid: the influence of flow regime (e.g. stratified, wavy, annular mist, slug, etc.) on corrosion which is commonly known as “Flow-Induced Corrosion-FIC” can be attributed to increased fluid turbulence intensity and mass transfer as a result of flowing a fluid over a surface [7]. A prevalent example of this is occurrence of slug flow in the pipeline which is known to remarkably reduce the corrosion inhibitor efficiency [8]. Liquid-holdup is another important hydrodynamic parameter for gas-liquid flow in pipelines and flow lines. When two phases are transported in a pipe, the flow velocity is frequently inadequate to uniformly transport both phases at the same rate. As a result, the gas flows faster than the liquid and there is a hold-up of liquid that may accelerate corrosion. This means that the volume of liquid in some areas along the pipeline is higher than the normal liquid to gas ratio. For wet gas system, liquid-holdup was found to strongly depend on gas velocity and the angle of pipeline inclination [9, 10].
- Top-of-line corrosion: When the flow pattern in wet gas pipeline is stratified or wavy, corrosion at top of the line can occur due to presence of fatty acids such as HAc and

water condensation because of cooling of the fluid. The condensed water which is free from pH buffers such as bicarbonates has low pH and is very corrosive. The condensed water can become rapidly supersaturated with corrosion products, resulting in increased pH and iron carbonate film formation [3]. If the rate of condensation is high (namely greater than $0.25 \text{ g/m}^2/\text{s}$), plenty of acidic water flows down the internal pipe walls leading to a very corrosive situation [11].

- pH buffers: pH has a significant direct effect on the corrosion rate and indirect influence on FeCO_3 formation: the higher the pH, the less corrosive the system is as there are fewer H^+ ions in solution and the solubility of FeCO_3 decreases, leading to supersaturation and a high precipitation rate. Some of the corrosion models include a built-in module to estimate pH based on the water chemistry (ion strength, bicarbonates, organic acids, etc.) as well as partial pressure of CO_2 and H_2S . However, it was observed in a number of reports that for the purpose of corrosion rate assessment some sort of in-house developed spreadsheets based on de Waard-Milliams model was used and the effect of pH buffers have not been properly addressed.
- Glycol/Methanol: in order to avoid hydrate formation in wet gas pipelines, glycol and/or methanol are often added to the fluid. The effect of glycol in reducing corrosion rate is attributed to changes in solution properties with increasing glycol concentration such as decreased CO_2 solubility, decreased CO_2 diffusivity, decreased water activity and decreased solution polarity [12].
- the effect of elemental sulfur: Elemental sulfur is often produced by sour gas wells, primarily due to the oxidation of hydrogen sulfide. This may occur as a result of oxygen contamination. Alternatively, with pressure and temperature changes in the line, sulfur may precipitate and deposit on the pipeline walls. In the presence of water, contact of solid sulfur with mild steel can result in the onset of catastrophic corrosion processes [13, 14]. The problem, which can be exacerbated by the presence of chloride ion and oxygen contamination, manifests itself as severe localized and pitting attacks.
- Steel type and chemistry: previous studies have indicated the profound effects of steel chemistry and microstructure on the corrosion rate. In De Waard-Milliam model, steels are categorized into two groups: 1) normalized and 2) quenched and temper. This factor, however, has not been considered in some of the reports.

Type 3 errors occur when a corrosion model is used beyond its range of validity. Since most of these models are semi-empirical, or even fully empirical with only a handful of the more recent models being based on mechanistic descriptions of the processes underlying CO₂ corrosion, then they have to be strictly used within the range of their validity. For instance, the following limitations apply to the Norsok M-506: temperature range of 5-150C, pH: 3.5-6.5, CO₂ partial pressure (in the gas phase): 0.1-10 bar, shear stress: 1-150 Pa, H₂S partial pressure (in the gas phase) <0.5 bar, ppCO₂/ppH₂S<20, concentration of organic acid>100ppm when ppCO₂<0.5 bar [15].

Type 4 errors occur as a result of utilizing a corrosion model for a specific set of service conditions for which the model is believed to be inaccurate even though the input lies within the validity range of the software. In fact, the results obtained from different corrosion models for the same case with exactly the same input data may be significantly different. This can be attributed to the arbitrary and empirical nature of correction factors for environmental parameters as well as the fact that the models are semi- or fully-empirical, so their accuracy depends on the quality of data used for their development. To explain this in more details, project 3 is selected as an example and the predicted corrosion rate reported in the corrosion study are evaluated as follows.

Project 3 is a subsea pipeline designed to carry sweet multiphase fluid. The project document indicates that Norsok M506 was initially used for prediction of CO₂ corrosion rate. For the purpose of verification of the reported results, ECE5.0, Cassandra 98 and Predict 6.0 have been used in this survey. Table 2 compares the unmitigated corrosion rates obtained by all four models.

Table 2 Summary of corrosion modeling results for project 3

	NORSOK M506	BP Cassandra	ECE 5.0	PREDICT 6.0
Total wall-loss (mm)in unmitigated condition	7.41	3.97	3.68	0.85

As it can be seen in table 2, Norsok M506 predicts a total wall-loss of 7.41mm over the design life of 20 years based on the inhibited corrosion rate. This rate is considerably higher than that of the others. This can be rationalized by considering the fact that Norsok M-506 estimate continuous increase in corrosion rate with an increase in temperature even at temperature ranges above scaling temperature, T_s. However, ECE5.0 and Predict6.0, which are based on de Waard- Milliams approach, predict an abrupt reduction in corrosion rate once

the carbonate scale is formed at or above T_s . BP Cassandra also predict a constant corrosion rate after this point [16]. Fig. 2 schematically illustrates variation of CO_2 corrosion rate as a function of temperature for the above-mentioned approaches.

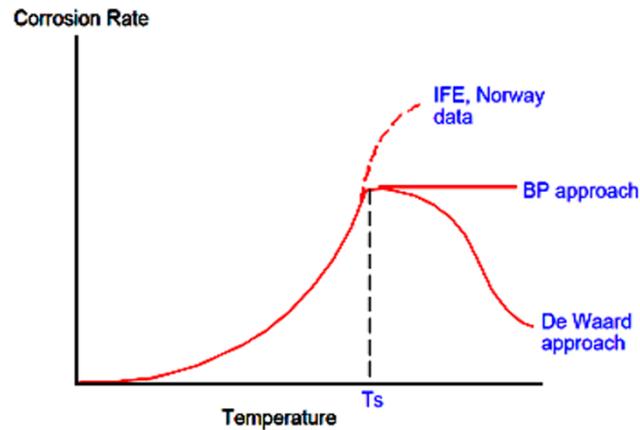


Figure 2 Possible effects of high temperature scaling on the corrosion rate [16].

Another reason underlying the fact that NORSOK-M506 overestimates corrosion rate for this case is that the model does not take the oil wetting effect into account. Based on the crude oil properties given in the project basis of design, it is expected that oil wetting effect play an important role in mitigating corrosion and thus neglecting this effect may result higher corrosion rates.

Table 2 also indicates that while ECE5.0 and Cassandra 98 give reasonably close predictions, Predict 6.0 estimate a very small wall-loss. This can be attributed to the strong dependence of the latter model to the oil wetting effect. The model also gives strong credit for pH so that at high pH, namely above 4.5-5, the model underestimates corrosion rate. The strong dependence of this model to the pH is also correlated to the effect of protective corrosion films and particularly effect of H^+ mass transport limitations [3]. In summary, one may conclude that neither NORSOK M506 nor Predict 6.0 is the best corrosion models for prediction of CO_2 corrosion rate in the case of project 3.

To avoid the above pitfalls the following precautionary steps are recommended to be taken.

- The user of a corrosion model should first justify the suitability of that model for the specific job.
- Ensure that the input data are within the range of validity of corrosion model.

- Select the right corrosion model which is best suited for the project considering the range of environmental data, service conditions, and fluid properties. Table 3 gives preliminary guideline on selection of the right model.
- Validate the predicted results by running at least two or three corrosion models. It is always better to use corrosion models which were developed based on different concepts (e.g. NORSOK M506, Cassandra, and de Waard- Milliams)
- Collate actual corrosion monitoring field data on the existing assets of the same project (if they are available) or other assets which are similar in terms of operating conditions and chemistry of service fluid and then validate/adjust the predicted corrosion rates.

Table 3 important factors in CO₂ corrosion prediction models [3]

Model	De Waard-Milliams	NORSOK M506	Hydrocor	Corplus	Cassandra	KSC	Multicorp	ECES.0	Predict 5.0	Tulsa model	ULL	CorPos	OLI Model	SweetCor
Lab data, Field data model, Mechanistic model	L	L	M	F	L	M	M	L	L	M	F	L	M	L
Scale effect formation water*	N	M	N	W	W	M	M	W	S	S		M	W	W
Scale effect condensed water*	W	M	W	W	W	M	M	W	S	S		M	M	W
Effect of pH on corrosion rate*	W	M	W	M	W	M	M	W	S	S	S	M	W	W
Risk for localized attack				Y		Y			Y		Y			
Oil wetting effect crude oil*	S	N	M	M	N	N	S	S	S	N	S	M	N	N
Oil wetting effect condensate*	N	N	N	M	N	N	M	M	M	N	S	M	N	N
CaCO ₃ correction for pH				Y			Y						Y	
Effect of organic acid on corrosion			Y	Y	Y		Y	Y	Y		Y			
Top of line corrosion	Y		Y				Y	Y			Y			
Effect of H ₂ S on corrosion rate*	N	N	W	N	N	N	M	S	S	N	W	N	S	N
Multiphase flow	N	P	M	P	N	N	P	M	P	P	M	M	N	N

calculation**														
Max. temperature limit °C	140	150	150	150	140	150	100	140		115		150	120	120
Max. CO2 partial pressure bar	10	10	20	20	10	20	20	20	70	17		10	20	
Open, Commercial, Proprietary	O	O	P	O	O	O	P	C	C	P	P	P	C	P

* S - strong effect, M - moderate effect, W - weak effect, N - no effect ** P - point calculation, M - multiphase profile calculation, N - no multiphase flow calculation

CONCLUSIONS

In the present study a survey was carried out on 15 offshore hydrocarbon production and transportation projects in an attempt to address the common human errors occurring in the process of corrosion rate assessment and materials selection. The outcome of the survey was that the majority of cases studied (namely 14 out of 15) suffered from different degree of flaws and errors which resulted in over- or under-estimation of corrosion rates. The errors were classified into four main types: (1) utilizing inadequate or false data as the input to the model, (2) failing to address factors which may have significant influence on corrosion rate, (3) utilizing corrosion models beyond their validity range and (4) utilizing a corrosion model for a specific set of input, where the model is found to be inaccurate even though the input is within the software validity range. To avoid the above-mentioned errors, some precautionary steps were recommended to be taken.

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