



Prediction of Generalised and Localised Carbon Steel Corrosion Using Improved Norsok and Papavinasam Models

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Authors' contributions

This work was carried out in collaboration among all authors. Author OAF designed the study and wrote the protocol. Author AIA carried out the study under the supervision of author OAF. Author AIA wrote the first draft of the manuscript while author AS revised it. All authors read and approved the final manuscript.

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ABSTRACT

In this study, Norsok and Papavinasam models have been improved so as to reduce the model limitations. The Norsok model was improved by accounting for 3 phase flow in calculating the wall shear stress and correcting for oil wetting and formation of protective layers in steel pipes during hydrocarbon transportation while the Papavinasam model was improved by using the Weibull distribution to account for time effect in corrosion predictions. The corrosion rates predicted fairly agreed with the field values. The improved models are user friendly and readily available and thus applicable for corrosion studies in the oil and gas industry.

Keywords: Corrosion; carbon steel; Norsok model; Papavinasam model; weibull distribution.

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1. INTRODUCTION

Corrosion is defined as “the deterioration of a material, usually metal, by the reaction with its environment” [1]. Internal and external corrosion is common in carbon steel pipelines carrying oil and gas containing corrosive components such as CO₂, H₂S and water. If these agents are present in the fluid stream in considerable quantities, internal corrosion of the pipe walls is inevitable.

In order to avoid the side-effects of internal corrosion, the corrosion rate needs to be monitored and minimised as applicable. To do this, there is a need to develop models that can accurately predict the generalised and localised corrosion rate in carbon steel pipes based on given field data. As a result, several models have been put forward over the years although no standard model exists for corrosion prediction in the industry.

De Waard and Milliams [2] indicated that corrosion rate increases with CO₂ partial pressure and temperature until it reaches a maximum value at temperature 60-70°C and then decreases until 90°C. De Waard and his co-worker [3] proposed a semi-empirical model using data acquired from a high pressure test facility. Their model accounts for the contributions of kinetics of corrosion reaction and mass transfer of dissolved carbon dioxide. Their model, however, doesn't account for the oil composition.

Jepson and his co-workers [4] developed an empirical model for corrosion rate prediction in horizontal multiphase slug flow pipelines. Their model relates the corrosion rate to the pressure gradient across the mixing zone, water cut, temperature, and CO₂ partial pressure. The model has been improved in 1997 to account for the effect of slug frequency and oil type [5].

A mechanistic model for CO₂ corrosion in horizontal multiphase slug flow has been proposed in 2002 by Hongwei Wang and his co-workers [6]. Their model covers the electrochemical reactions on steel surface, the chemistry of fluid, and mass transfer between the metal surface and the fluid.

Srdjan Nestic and co-workers developed a comprehensive model for internal corrosion prediction in mild steel pipelines [7]. The effects of many factors affecting the corrosion rate such

as H₂S, water entrainment in multiphase flow, corrosion inhibition by crude oil components and localised attack have been taken into account in the model.

In this work, the Norsok model for predicting generalised corrosion and the Papavinasam model for predicting localised corrosion have been modified and improved. The Norsok model was improved by accounting for 3 phase flow in calculating the wall shear stress and introduction of correction factors owing to oil wetting and formation of protective layers in steel pipes during transportation of hydrocarbon. The Papavinasam model was improved by using the Weibull distribution to account for time effect in corrosion predictions. Thus, CO₂ corrosion rates at different operating conditions have been predicted, validated against field data and analysed. The predicted corrosion rates fairly agreed with the measured field values.

2. NORSOK MODEL

A pictorial view of the corrosion mechanism in oil and gas tubings is shown in Fig. 1. The flow of hydrocarbons containing CO₂, H₂S and H₂O results in corrosion of the tubing surface.

The original governing equation of the Norsok M-506 model thus depends on partial pressure of CO₂, partial pressure of H₂S, medium pH, and system temperature as well as the tangential stress at liquid solid interface as shown in equation 1 below:

$$R_c = K_t * f_c * \phi(\text{pH})_t * \left(\frac{S}{19}\right)^{0.146 + 0.0324 \log f_c} \quad (1)$$

where:

R_c is the corrosion rate in mm/year
 K_t is a temperature dependent constant
 $\phi(\text{pH})_t$ is a function of pH and temperature
 f_c is the fugacity of CO₂
 S is the tangential stress at fluid-solid interface

The above listed factors represent the main operational parameters in the model and will be individually analysed in the next section. For simplifications, the following assumptions are made:

- i. Only CO₂ and H₂S are the corrosive species present in the fluid stream
- ii. The pH of the system varies only with temperature.

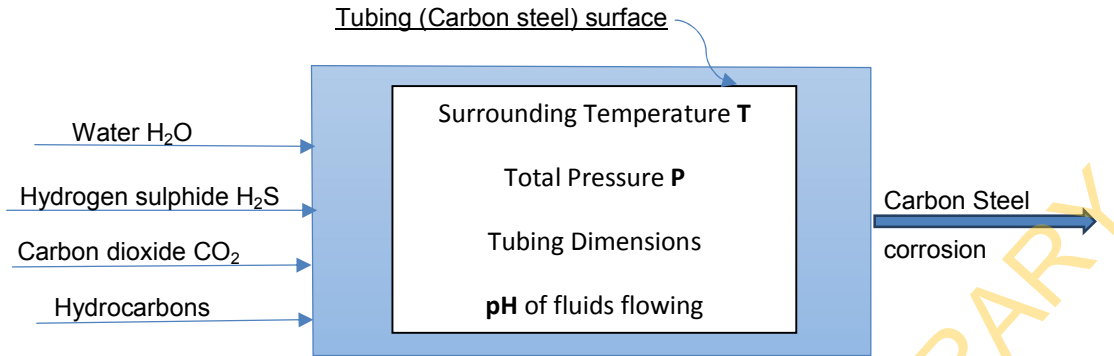


Fig. 1. Physical model depicting corrosion mechanism in the tubing

- iii. Corrosion is uniform over the target surface of the tubing
- iv. Fluid density and viscosity varies with temperature alone
- v. Sand production is negligible.

Each of the parameters making up the Norsok model is reviewed and modified. For the temperature dependent parameter K_t , an improved equation is obtained that relates temperature T with K_t as shown in Table 1.

Table 1. K_t constant values versus temperature

Temperature (°C)	Constant parameter (K_t)
20	4762
40	8927
60	10695
80	9949
90	6250
120	7770
150	5203

The fugacity parameter f_c is modified by incorporating the effects of H_2S if the partial pressure of H_2S (P_H) is above 0.01psi and the ratio of the partial pressure of CO_2 (P_C) to H_2S is greater than 200. The resulting equation thus becomes:

$$P_{Ceff} = 10^{\frac{\log(P_C) + \log(P_H) + \log(HCO_3^-)}{2}} \quad (2)$$

Where P_{Ceff} is the effective partial pressure of CO_2 and (HCO_3^-) is the concentration of the bicarbonate ion.

Thus the resulting fugacity becomes

$$f_c = a \cdot P_{Ceff} \quad (3)$$

where 'a' is the fugacity constant.

The tangential stress at fluid-solid interface is a parameter which depends upon the flow regime, fluid properties as well as the quality of the metallic surface. For this purpose, the average tangential stress is used. This is given by:

$$S = 0.5 \cdot \rho_m \cdot f \cdot u_m^2 \quad (4)$$

where:

S is the tangential stress at interface, Pascal (Pa)

ρ_m is the average fluid density kg/m^3

f is the friction coefficient

U_m is flow rate m/s

This parameter is used to couple the Norsok model into applicability for 3 phase flow by computing the densities and viscosities of gas, oil and water via empirical correlations. The mixture density is given by:

$$\rho_m = \rho_l \cdot \alpha + \rho_g (1 - \alpha) \quad (5)$$

where:

ρ_l is liquid density kg/m^3 ;

ρ_g is gas density at the system pressure;

α is the liquid fraction mixture which can be expressed as:

$$\alpha = \frac{Q_l}{Q_l + Q_g} \quad (6)$$

where:

Q_l is the liquid volumetric flow rate, m^3/s ;

Q_g is the gas volumetric flow rate, m^3/s

The liquid stream is a mixture of oil and water, thus taking into account the water fraction β , the liquid density can be expressed as:

$$\rho_l = \rho_w \cdot \beta + \rho_o \cdot (1 - \beta) \quad (7)$$

where:

ρ_w is the water density, kg/m³;
 ρ_o is the oil density, kg/m³

The viscosity of the mixture is computed in a similar way and various empirical correlations are employed to find the values of each of the variables. The friction factor is also computed for both laminar and turbulent flow using the Churchill model and taking into account 3-phase flow.

Applying the law of logarithm which states that **log (ab) = log a + log b** to equation (1):

$$\log R_c = \log K_t + \log f_c + \log \phi(\text{pH})_t + \log \left(\frac{S}{19}\right)^{0.146 + 0.0324 \log f_c} \quad (8)$$

This thus linearises the model equation. The major factor that differentiates one model from the other is the effect of the protective layer formed on the metal surface. Other factors includes: effect of water wetting, effects of corrosion inhibitors, effect of H₂S and effect of total pressure. Two of these factors were considered in this work:

2.1 Effect of Protective Surface Layer

In corrosion environments, a protective layer could form at elevated temperatures and due to the precipitation of FeCO₃ or Fe₃O₄. This is because iron reacts with the weak carbonic acid formed by the presence of CO₂ at very high temperatures chemically.

A correction factor F_{scale} is thus defined in order to account for the effect of surface layers:

$$\log F_{\text{scale}} = \frac{2400}{T} - 0.6 \log (f_c) - 6.7 \quad (9)$$

where:

T is the temperature, °C;
 f_c is the fugacity of CO₂

Thus the correction factor $\log F_{\text{scale}}$ is added to the corrosion rate $\log R_c$ when the input temperature T_i is higher than T_{scale} which is given as:

$$T_{\text{scale}} = \frac{2400}{0.6 \log (f_c) + 6.7} \quad (10)$$

2.2 Effect of Oil Wetting

In corrosion studies, the steel is assumed to be wetted with oil if the water is entrained in the crude (water-in-oil emulsion). This is achievable at high flow rates and low water cut (below 30%). When the flow rate is low and water cut (W_c) is greater than 30%, water drops out of the oil film and wets the pipe surface instead despite increasing the corrosion rate considerably. Hence, the correction factor denoted by F_{wc} in this context is given a value of 0.1 at 5% water cut (minimal corrosion) and a value of 1.0 at 30% water cut (severe corrosion) and is given by:

$$F_{wc} = 1 - 0.036(30 - W_c) \quad (11)$$

In general, if **temperature T is less than scaling temperature T_{scale}** , equation (8) is applicable. Should $T > T_{\text{scale}}$, the equation becomes:

$$\log R_c = \log K_t + \log f_c + \log \phi(\text{pH})_t + \log \left(\frac{S}{19}\right)^{0.146 + 0.0324 \log f_c} + \log F_{\text{scale}} \quad (12)$$

Also, if the above holds and **water cut is greater than 5%**, the equation becomes:

$$\log R_c = \log K_t + \log f_c + \log \phi(\text{pH})_t + \log \left(\frac{S}{19}\right)^{0.146 + 0.0324 \log f_c} + \log F_{\text{scale}} + \log F_{wc} \quad (13)$$

2.3 Using Norsok Model for Qualitative Localised Corrosion Prediction

In oil and gas environments, two processes usually occur as the fluid flows. These processes are the actual corrosion process and the precipitation process. The corrosion process leads to metal loss while the precipitation process leads to metal protection. In order to create a balance between both processes, a single parameter “protective tendency” (PT) which is the ratio of both effects is defined based on the assumption that the nature of corrosion attack depends on the balance of the processes occurring in the corrosion environment. Mathematically, the protective tendency can be expressed as:

$$PT = \frac{R_c}{R_p}$$

where:

R_c is the uniform corrosion rate
 R_p is the precipitation rate of iron carbonate FeCO₃ and iron sulphide FeS

From chemical kinetics, the precipitation rate of FeCO₃ formation is given by:

$$R_{FeC} = K_{spFeC} \cdot f(T_{FeC}) \cdot f(A/V) \cdot (S_{FeC} - 1) \cdot (1 - S_{FeC}^{-1}) \quad (15)$$

where: K_{spFeC} is the solubility product for FeCO₃.

The expression $f(T_{FeC})$ is an Arrhenius function that accounts for temperature given by:

$$f(T_{FeC}) = e^{-\frac{119.8}{RT}} \quad (16)$$

where:

T is the temperature

$f(A/V)$ is the surface area to volume ratio;

S_{FeC} is the solution supersaturation with respect to FeCO₃

The protective tendency is only an indication of how likely it is for localised corrosion to occur without any idea of how severe the corrosion would be should it occur. In order to predict the severity of localised corrosion, a severity indicator called the pitting factor and denoted by F_p is defined:

$$F_p = \frac{R_{pit}}{R_c} \quad (17)$$

where:

R_{pit} is the maximum penetrating rate, mm/year;

R_c is the uniform corrosion rate, mm/year.

According to the Pot's model, R_{pit} can be expressed as:

$$R_{pit} = \frac{MW_{Fe}}{\rho_s} \cdot C_{Fe} \cdot \frac{WCR}{\rho_w} \quad (18)$$

where:

MW_{Fe} is molecular weight of iron, (55.847 g/mol);

C_{Fe} is the iron concentration, mol/l;

ρ_s is the density of carbon steel, (7860 kg/m³);

ρ_w is the density of water, (varies with temperature);

WCR is the water condensation rate, g/m²/s.

On substitution:

$$R_{pit} = 224069.59 C_{Fe} \cdot \frac{WCR}{\rho_w} \text{ mm/year}$$

3. THE PPAVINASAM MODEL

The modified Norsok model is a qualitative tool in estimating localised corrosion. In order to obtain the magnitude of localised corrosion and the probability of it occurring at various conditions, the Papavinasam model comes in handy. The localised pitting corrosion in sweet or sour oil and gas production environments depends not only on the partial pressure of CO₂ and H₂S but also on a number of other parameters including oil, water, gas, solid content, temperature, total pressure, concentration of sulphur and sulfate, concentration of bicarbonate as well as concentration of chloride. The equations associated with these parameters are:

$$CR_{HS} = (-0.54P_H + 67)/40 \quad (20)$$

where: P_H is the partial pressure of H₂S in psi or 6.9 P_H in kPa

$$CR_S = (0.85[S] + 9.7)/40 \quad (21)$$

where: [S] is the concentration of sulfur in gram/liter in aqueous phase

$$CR_{CO} = (-0.63P_C + 74)/40 \quad (22)$$

where: P_C is the partial pressure of H₂S in psi or 6.9 P_H in kPa

$$C_{TP} = (-0.08P_{Total} + 88)/40 \quad (23)$$

where: P_{Total} is the total pressure of in psi or 6.9 P_H in kPa

$$C_{Temp} = (0.57T + 200)/40 \quad (24)$$

where: T is the temperature of the system.

$$C_{Flow} = (0.19W_{SS} + 64)/40 \quad (25)$$

where: W_{SS} is the wall shear stress in Pascal (Pa)

$$C_{Oil} = (-0.33\Theta + 55)/40 \quad (26)$$

where: Θ is the contact angle

The short time frame of the Papavinasam model data validity is its major limitation. Thus, the Weibull distribution is used to develop a modified model that can scale up the observed corrosion rates long-term and far into the future and also account for the synergistic effects of all individually acting parameters. The general

expression for the Weibull probability distribution is given by:

$$f(x; \lambda, k, \Theta) = \frac{k}{\lambda} \left(\frac{x-\Theta}{\lambda}\right)^{k-1} e^{-\left(\frac{x-\Theta}{\lambda}\right)^k} \quad (27)$$

for all $x \geq 0$ and $f(x; \lambda, k, \Theta) = 0$ for $x < 0$

where:

- x is the Weibull random variable;
- $\lambda > 0$ is the scale parameter;
- $k > 0$ is the shape parameter;
- $\Theta \geq 0$ is the location parameter

The expected value of the distribution is given as:

$$EV(x) = \int_{-\infty}^{\infty} k \cdot x \cdot \frac{1}{\lambda} e^{-\left(\frac{x}{\lambda}\right)^k} dx \quad (28)$$

The **cumulative distribution function** for the Weibull distribution is given as:

$$F(x; \lambda, k) = 1 - e^{-\left(\frac{x}{\lambda}\right)^k} \quad (29)$$

for all $x \geq 0$, and $F(x; \lambda, k) = 0$ for $x < 0$

On Microsoft excel solver, the Weibull distribution can be computed directly and incorporated into the developer plug in on Microsoft excel. In Microsoft excel, option 'TRUE' corresponds to the cumulative distribution function while option 'FALSE'.

The **failure rate** 'h' (or hazard function) is given by:

$$h(x; \lambda, k) = \frac{k}{\lambda} \left(\frac{x}{\lambda}\right)^{k-1} \quad x \geq 0; k > 0; \lambda > 0 \quad (30)$$

This is a time function that depict the rate at which the tubing or any other production system will fail with time. It can also be used to evaluate the probability that the system in question will fail or not fail after some time of usage.

The **survival function** 'S' of the Weibull distribution is given by:

$$S(x) = e^{-(x^k)} \quad x \geq 0; k > 0 \quad (31)$$

This indicates the probability that a particular system will survive a particular period of usage and whether such system will last throughout its expected life or break down before the mean effective lifetime is attained.

4. RESULTS AND DISCUSSION

4.1 Uniform Corrosion Prediction

Using data from a particular field X in the Niger Delta region of Nigeria for 3 different cases to first validate the revised Norsok model for uniform corrosion, the results obtained from both field results and that predicted by the model are as shown in Table 2.

From the Table 2, it is observed that the corrosion rates predicted by the modified model falls within the range of corrosion rates for case 1 (57°C to 104°C). For case 2 (54°C), the predicted corrosion rate of 3.8 mm/yr is approximately close to the field corrosion rate of 4.0 mm/yr. Similarly for case 3 (58.7°C), the predicted corrosion rate is acceptable compared to the field corrosion rate observed. For cases 2 and 3 with gas production, the model is expected to yield more accurate results as the model was specially modified for 3 phase turbulent flow.

Table 2. Validation of the modified Norsok model

T°C	P _{Total} (bar)	P _c (bar)	pH	D (m)	V _m (m/s)	Q _o (m ³ /d)	Q _w (m ³ /d)	Q _g (m ³ /d)	Field CR (mm/yr)	Predicted CR (mm/yr)
57	270	1.56	5.05	0.1	3.63	760	40	-	4.6-10	4.8
80	250	1.56	4.99	0.1	3.85	549	671	-	4.6-10	6.7
66	287	1.56	4.92	0.1	3.58	760	40	-	4.6-10	5.4
85	269	1.56	5.10	0.1	3.65	549	671	-	4.6-10	7.2
107	369	1.56	5.06	0.1	1.31	549	671	-	4.6-10	9.6
104	375	1.56	5.06	0.1	1.12	760	40	-	4.6-10	9.1
54	95	1.20	4.00	0.308	4.51	450	50	5.00E ⁶	4.0	3.8
58.7	12.9	0.0645	5.74	0.258	5.20	4450	1907	1.56E ⁶	1.1	1.2
58.7	12.9	0.0645	6.30	0.258	5.20	4450	1907	1.56E ⁶	1.0	0.8

Having validated the modified model, data from another field Y in the Niger Delta region is used to compare the predictions of the original Norsok model and the modified Norsok model as shown in Table 3. The resulting error is analysed using Average Absolute Relative Error (AARE) and Mean Square Error (MSE) error parameters.

From the Table 3, the modified model yields better predictions with lesser errors compared to the original Norsok model. Fig. 2 also depicts the variation of this modified model and the original model from field data.

Having compared the original and modified Norsok models, other commonly used empirical correlations are also compared with the modified

model in order to investigate its performance as shown in Table 4.

Analysis of the results in Table 4 indicates that this study yields the most accurate predictions with smaller error margins as seen in its value of AARE compared to other empirical correlations as shown in Fig. 3.

4.2 Qualitative Localised Corrosion Prediction

Here, the precipitation rate is computed alongside the uniform corrosion rate which is then used to compute the protective tendency PT. The input parameters as obtained from field A as well as the computed rates are outlined in the Table 5 [8].

Table 3. Comparison of the Norsok and modified Norsok model

T°C	P _{Total} (bar)	P _c (mol%)	P _H (ppm)	pH	D _{in} (m)	V _{so} (m/s)	V _{sw} (m/s)	Average CR (mm/yr)	This study CR (mm/yr)	Norsok Model CR (mm/yr)
44.0	24.0	3	0.5	5.81	0.581	0.59	0.06	1.6	1.9	2.3
44.0	24.0	3	0.5	5.81	0.581	0.59	0.06	1.6	1.8	2.3
44.0	24.0	3	0.4	5.81	0.581	0.59	0.06	1.4	1.6	2.3
44.0	24.0	3	0.4	5.81	0.581	0.59	0.06	0.9	1.2	2.3
43.9	24.0	3	0.3	5.83	0.581	0.59	0.06	1.3	1.4	2.3
43.9	24.0	3	0.3	5.83	0.581	0.59	0.06	1.4	1.6	2.2
43.8	23.9	3	0.3	5.85	0.581	0.59	0.06	1.9	1.9	2.1
43.6	23.9	3	0.0	5.87	0.581	0.59	0.06	1.8	2.0	2.1
43.2	23.8	3	0.0	5.87	0.581	0.59	0.06	1.4	1.6	1.8
39.1	22.2	3	0.0	5.91	0.581	0.59	0.06	1.1	1.4	1.6

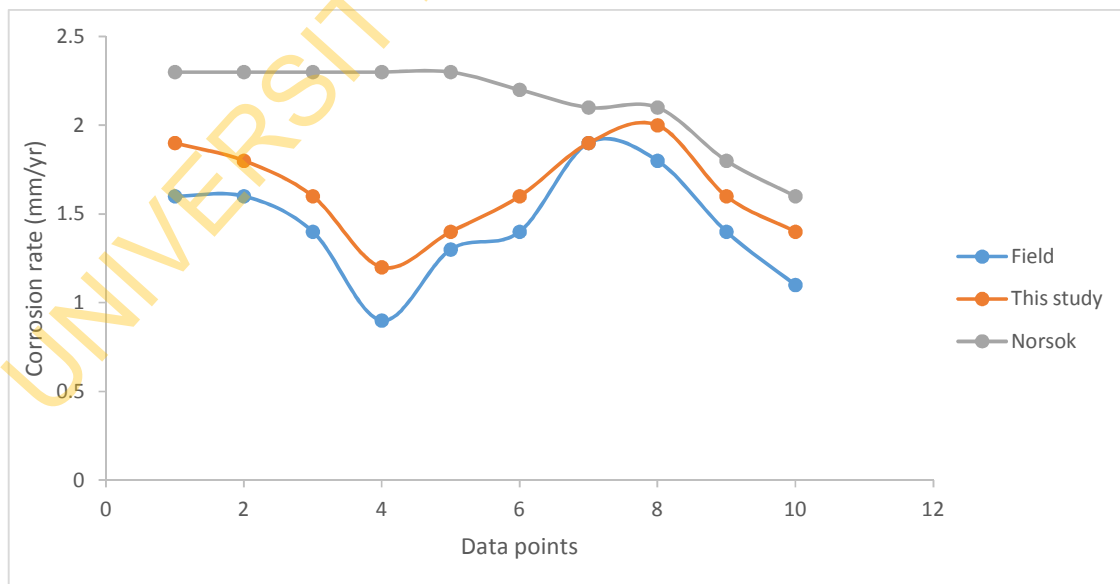


Fig. 2. Variation of modified and original model with field data

Table 4. Comparison of modified model with other empirical models

Empirical models	Observed CR (mm/yr)	Model CR (mm/yr)	AARE	SD	MSE
De Waard	1.6	2.6	0.38462	0.50000	0.70711
Lotz	1.6	3.3	0.51515	0.85000	1.20208
Mishra	1.6	3.2	0.50000	0.80000	1.13137
Oddo	1.6	2.4	0.33333	0.40000	0.56569
Jepson	1.6	2.5	0.36000	0.45000	0.63640
Norsok	1.6	2.3	0.30434	0.35000	0.49497
This study	1.6	1.9	0.15789	0.15000	0.21213

Table 5. Analysis of likelihood occurrence of localised corrosion

Parameters	Observed values
Total pressure (bars)	235-260
Temperature (C)	100
Oil production (bopd)	1500
Water cut (%)	40-70
CO ₂ content (mole %)	2.5
H ₂ S content (mole %)	Nil
pH (20C)	7.2
GOR (scf/stb)	70-200
Tubing size (inch)	2 ³ / ₈ – 3 ¹ / ₂
Fe ²⁺ content (mg/l)	755
Carbonate content (mg/l)	610
Sulfate content (mg/l)	-
Field corrosion rate (mm/yr)	1-4
Predicted corrosion rate (mm/yr)	1.2-3.1
Precipitate growth rate (mm/yr)	1.2-1.4
Protective Tendency PT	1.25-1.33

From the results in Table 5, the corrosion rate predicted for a uniform shear stress of 75 Pa is within range of the field corrosion rate thus the justification to further compute protective tendency of the tubing. The value yielded was greater than 1.0; thus there is a likelihood of about 20%-40% for corrosion to occur. Put in another way, the probability of localised corrosion occurring is about 0.3 +/- .1. If the value of PT is less than 1, this implies that there is little or no likelihood for localised corrosion to occur as the rate of precipitation exceeds the rate of corrosion of the tubing. This means that the metal surface is protected faster than it is being corroded.

If the tendency of localised corrosion prediction has been determined as shown in the previous section and a high likelihood of occurrence is observed, the model can be further used to compute the severity of the localised corrosion if

it actually occurs. Table 6 shows the severity of likely localised corrosion using the same data points as above and a water condensation rate of g/m²/s.

Table 6. Severity of likely localized corrosion

Parameters	Observed values
Total pressure (bars)	235-260
Temperature (C)	100
Water cut (%)	40-70
Water condensation rate (mL/m ² /s)	1.6 ± 0.1
Computed water density (g/cc)	0.9581
Predicted corrosion rate (mm/yr)	1.2-3.1
Maximum pitting rate (mm/yr)	2.56
Pitting factor	1.19

Analysis of the results in Table 6 shows that at relatively high water cuts and moderate water condensation rates, the maximum penetrating rate is fairly high; this consequently leads to a pitting factor greater than 1. This implies that the amount of water present in a flowing stream of hydrocarbon as well as the rate at which the water condenses greatly affects the severity of localised corrosion as water is the main facilitator of corrosion in steel pipelines. Thus to reduce the likelihood of corrosion, water cut should be monitored and if the water cut exceeds the threshold (30% water cut), it is advisable to use corrosion inhibitors in order to reduce the likelihood of localised corrosion.

4.3 Quantitative Localised Corrosion Prediction

Under this section, the model computes the individual pitting corrosion rates first and then calculates the synergistic corrosion rate as well as a Weibull probability distribution for the computed corrosion rates as shown in Table 7.

Table 7. Localized corrosion rates and corresponding Weibull distribution functions

T°F	P _{Total} (psi)	P _c (psi)	P _H (ppm)	ID (in)	V _m (m/s)	Q _o (m ³ /d)	Q _w (m ³ /d)	Q _g (m ³ /d)	HCO ₃ (ppm)	SO ₄ (ppm)	Model CR (mm/yr)	Weibull distribution CR
74.0	879.7	8.00	0.00	15.24	31.63	0.00	1982.17	6767.72	400.0	533.0	0.17	0.3303146
70.0	857.7	18.41	2.00	15.24	31.85	30.28	2265.34	679.6	420.0	1300.0	0.03	0.0599460
70.0	971.7	17.56	0.00	22.20	32.58	82.72	9344.55	0.00	220.0	0.00	0.088	0.1746423
65	868.7	17.13	1.40	22.20	31.65	130.69	1415.84	11425.85	700.0	66.8.280	0.075	0.1491586
55	904.4	15.06	3.20	12.02	32.11	2123.5	671.3	322.41	330.0	27.0	0.055	0.1096678
46	919.4	16.82	0.00	12.02	33.21	2115.8	40.342	231.65	600.0	0.00	0.0049	0.0097998
63	812.3	20.89	1.09	14.62	31.34	3123.6	50.231	0.00	774.0	20.00	0.0075	0.0149992
59	811.5	18.00	0.07	14.62	32.43	3421.7	1907.65	0.00	214.0	36.00	0.032	0.0639345
51.7	909.4	17.73	0.42	8.63	31.45	3542.3	1907.98	0.00	504.0	54.00	0.038	0.0758903

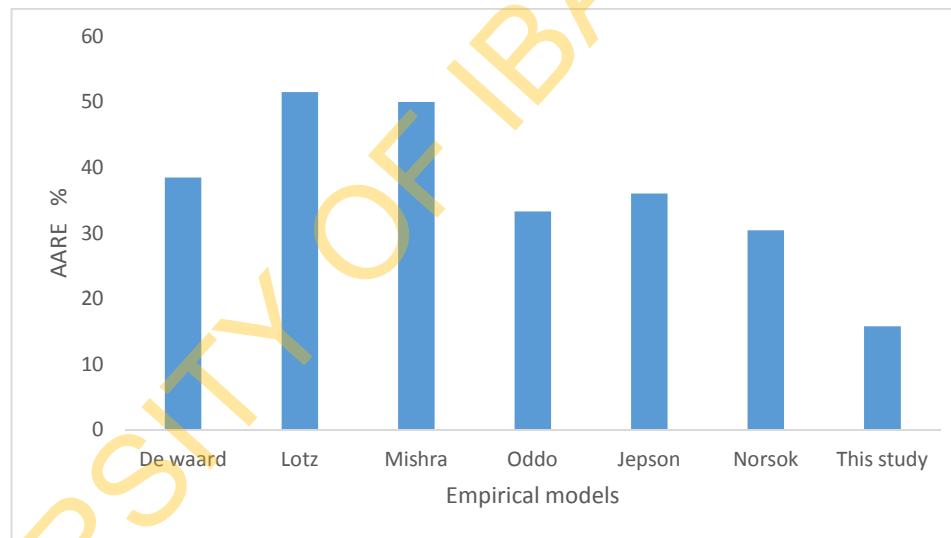


Fig. 3. Bar chart showing the average absolute relative error in %

It should be noted that the model can still compute the synergistic corrosion rates even if some of the parameters are not available as observed above. The Weibull distribution is employed in order to scale the observed corrosion rates over time i.e account for time effect of the Weibull distribution. Thus the distribution values are the localised corrosion rates that would occur later in the life of the production tubing over time. This is observed to be almost double of the mean corrosion rate that would be observed without factoring in the effect of time. Thus the Weibull distribution corrosion rate (CR) displayed on the table is the expected value (EV) of the Weibull distribution using a shape parameter of 2 and a scale parameter of 10.

5. SUMMARY AND CONCLUSION

The original Norsok model has been modified in order to improve its accuracy and its applicability. The modified model was further coupled to predict the tendency of localised corrosion and its severity should it occur. The Papavinasam model was also improved using the Weibull distribution to account for time effect as well as the survival and failure rate of systems undergoing localised corrosion. A visual basic computational package with friendly graphical user interface has been developed in order to implement the modified models. The predicted corrosion rates were validated against field data including that of the Niger Delta region in Nigeria and then analysed for accuracy and errors.

Currently, there is no universally accepted standard for prediction of CO₂ and H₂S corrosion as there are various models in the industry which yield different results for the same set of input parameters. As a result, engineering decisions based on tubing material selection and determination of tubing corrosion allowance will depend on the particular predictive model that is used. Although a high uncertainty is always linked to CO₂ and H₂S corrosion prediction, this can be minimised by using of applicable correction factors and continuous research into more accurate CO₂ and H₂S prediction models.

Should the accuracy of a particular model be doubted, various models can be used and compared and corrosion inhibitors can be injected into production wells as a last resort in mitigating the hazardous effects of tubing corrosion.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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