

Development of a Computer Software for Determining the Corrosion Rate of Oil Pipelines in CO₂ Environment Using Modified NORSOK M-506 Model

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Abstract

The problem of Carbon dioxide (CO₂) corrosion is of primary concern in Nigeria's oil and gas industry. This work attempted to develop a CO₂ corrosion rate prediction model, implement the model, simulate and validate it against operating field data with the intent of developing corrosion prediction software for the Nigerian oil and gas environment.

Existing models for CO₂ corrosion prediction were accessed. Modification of one of the models; the NORSOK M-506 model was carried out by incorporating a temperature model to it and also by modifying the wall shear stress parameter of the model to suit the Nigerian light crude oil. The entire model was implemented using Visual Basic to create computational software. With the developed computational software, simulation and prediction of CO₂ corrosion rate and the analysis of effects of various parameters such as temperature, fluid velocity, pH factor, CO₂ fugacity, mixture density, mixture viscosity and wall shear stress on corrosion rate along the pipeline length were carried out using the operating field data in the Nigerian oil and gas industry.

The mixture density and viscosity of the fluid were found to increase along the pipeline length as the temperature decreased. These resulted in increase in the pipeline wall shear stress and consequently increased the corrosion rate along the length of the pipeline. Other results obtained were in agreement with similar works done in this field of study. The developed computer software also predicted

corrosion rates that were in agreement with measured corrosion rates from operating field data. In addition, the modified model had a good agreement with De Waard and Lotz semi-empirical model and with HYDROCOR, a mechanistic model used in some of the Nigerian oil and gas industry. It had a standard error (SE) of 0.18. And at 95% confidence level, confidence interval (CI) of the model was between 0.70 and 1.41 mm/year mean corrosion rate predicted.

With the results obtained using the modified NORSOK M-506 model, it can be concluded that the model can adequately replace the models presently used in the Nigerian oil and gas industry for prediction of corrosion rates.

Keywords: Corrosion rate prediction, CO₂ corrosion, corrosion, computer software, model, pipeline.

1.0 Introduction

Corrosion is defined as the destructive attack of a metal by chemical, or electrochemical, reaction with its environment [1]. Corrosion usually occurs because the general tendency of metals is to return to their native form, which results in the lowering of their free energy and attainment of a more thermodynamically stable state [2]. There are different forms of corrosion but it is rare that a corroding structure, or component, will corrode based on only one form. Most corrosion phenomena can be classified as either electrochemical or chemical corrosion [3]. Electrochemical corrosion occurs when the environment is a conducting liquid; hence it is also called wet corrosion. Chemical corrosion on the other hand occurs mainly as a result of chemical reaction of the metal with the gases within the environment; hence it is usually referred to as dry corrosion.

The increasing cost of pipelines failures due to corrosion in the oil and gas industry has increased interest in corrosion problems and their solutions. Corrosion failure of most facilities is often due to the degradation of materials used for their fabrication. In design, operation, and maintenance of oil and gas storage and production facilities, management of corrosion is critical. Materials reliability is becoming ever more important in our society, particularly in view of the liability issues that develop when reliability is not assured, safety is compromised, and failure occurs [1]. The problem of CO₂ corrosion is the primary concern in Nigeria's oil and gas industry as it constitutes a leading cause of

pipeline failure and a main component of the operating and maintenance costs of the industries [4]. In order to manage corrosion failures successfully, organisations have adopted a policy of “zero failures” or “no failures.” This management policy is usually implemented by using a combination of well-established strategies, innovative approach, and when necessary, experimental trials.

It has been reported that corrosion failure attributed to sour and sweet corrosion, which resulted from activities of Hydrogen Sulphide (H_2S) and CO_2 respectively, have contributed to over 50% of all pipelines failures [5].

The impact of corrosion in the oil and gas industry has also contributed significantly to the non-productive time (NPT) of 20 to 30% cost from exploration to production [6]. The annual cost associated with corrosion damage of structural components in the United States was found to be greater than the combined annual cost of natural disasters [7].

Pipelines transporting crude oil containing components such as CO_2 and H_2S have suffered internal corrosion due to the presence of these gases dissolved in water. One of the most prevalent internal corrosion problems in Nigerian oil and gas industry is carbon dioxide corrosion, which is also called sweet corrosion. Hydrogen sulphide corrosion, also called sour corrosion, is not commonly encountered in Nigeria's oil industry.

The selection of pipe for a particular situation is dependent on the material it is transporting, the pressure and temperature of the contents. The most commonly used material for petroleum pipelines is carbon steel (mild steel). This may be ascribed to its strength, ductility, weldability and its amenability to heat treatment for varying mechanical properties [8 - 11]. Carbon steel is by far the most important alloy used in the petroleum industry and it accounts for over 98% of the construction material, especially oil and gas transportation pipelines [12]. However, carbon steel does have more challenging requirements such as the need for better understanding of the environment, accuracy and reliability of the materials and corrosion performance. In both offshore and onshore oilfield production in Nigeria, the pipelines transporting oil and gas operate with the two-phase (oil-water) or three-phase (gas-oil-water) flow conditions. The flow system of this environment must be clearly understood and captured in the development of corrosion prediction softwares for Nigerian oil and

gas industries. In this work, the main focus is on the oil-water two-phase flow in pipelines transporting crude oil.

The use of computational softwares by engineers for the analysis of the effect of CO₂ corrosion on pipeline materials both at the design and operational stages has been reported [13]. However, developed computational softwares with the Nigerian content are scarce. This study attempted to develop a computer software that will be used to determine corrosion rate of oil pipelines in CO₂ environment, based on the operating parameters in the Nigerian oil and gas industry. The developed computer software is also expected to enable the prediction of the design life of oil pipeline, the severity level of the unmitigated corrosion rate and the mitigated corrosion rate of oil pipelines in CO₂ environment.

2.0 Research Methodology

To enhance the achievement of the objectives of this work, the following procedures were carried out in order to develop the CO₂ corrosion prediction model:

2.1 Accessing and Modifying the NORSOK STANDARD M-506 Model

The NORSOK M-506 standard was developed with broad petroleum industry participation (Statoil, Norsk Hydro and Saga petroleum). The model is owned by the Norwegian petroleum industry. The model is developed to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations. The NORSOK standards are normally based on recognized international standards. They are developed according to the consensus principle generally applicable for most standards work and according to established procedures. The NORSOK standard is limited to a method for calculation of corrosion rates in hydrocarbon production and process systems where the corrosive agent is CO₂ [14]. The NORSOK STANDARD M-506 corrosion model for prediction of corrosion rate, Equation 2.1, was obtained from literature [14].

$$CR_t = K_t \times (fCO_2)^{0.62} \times \left(\frac{S}{19}\right)^{(0.146+0.0324\log(fCO_2))} \times f(pH)_t \quad (2.1)$$

CR_t = corrosion rate at temperature 't' in mm/year, K_t = equilibrium constant at temperature t, fCO₂ = fugacity of CO₂ in bar, S = wall shear stress in Pascal (Pa) and f(pH)_t = pH factor at temperature t).

2.2 Development of the Temperature Distribution Model

The equation used to obtain the temperature of fluid pumping over the pipeline section of length (L) in cross sections (x), Equation (2.2), was developed using the conservation of energy equation for steady flow of a fluid in a pipe.

$$T_e(x) = T_s + (T_i - T_s) \times \left(\frac{T_e(L) - T_s}{T_i - T_s} \right)^{\frac{x}{L}} \quad (2.2)$$

Where T_e = exit mean fluid temperature, T_i = inlet mean fluid temperature, T_s = constant.

2.3 Predicting the Temperature Dependent Constant (K_t)

The constants for the temperature t , (K_t) were generated by NORSOK STANDARD M-506 for temperatures between 20°C and 150°C. These values were used in obtaining simulated temperatures by a linear extrapolation at the temperature above and below the desired temperature.

2.4 Predicting the pH Factor

With the predicted temperature, and a given pH value of the fluid, the pH factor of that particular temperature was predicted. pH function at different temperatures used in this work is as given by NORSOK STANDARD M-506 (2005) [14].

2.5 Development of the CO₂ Fugacity Model

The equation for calculating the fugacity of CO₂ (f_{CO_2}) was derived by multiplying the fugacity constant with the partial pressure of a gas, as shown in equation (2.3). This was utilized to calculate the fugacity of CO₂ for the system.

$$f_{CO_2} = a \times P_{CO_2} \quad (2.3)$$

Where f_{CO_2} = fugacity of CO₂, a = fugacity coefficient, P_{CO_2} = CO₂ partial pressure

NORSOK STANDARD M-506 (2005) [14] derived the fugacity coefficient, Equation (2.4) used to compute the fugacity coefficient as:

$$a = 10^{\left(P \times \left(0.0031 - \frac{1.4}{T} \right) \right)} \text{ for } P \leq 250 \text{ bar, } a = 10^{\left(250 \times \left(0.0031 - \frac{1.4}{T} \right) \right)} \text{ for } P > 250 \text{ bar} \quad (2.4)$$

(Where T is the temperature (°K) calculated using equation (2.2), while P, is the total system pressure in bar). The program was built to convert the Celsius unit to Kelvin.

2.6 Development of the Wall Shear Stress Model

Taitel *et al.*, [15] gave the Blasius type equation for calculating oil layer, mixed layer, water layer and the interfacial wall shear stresses as shown below:

$$S = \tau_w = \frac{(f_w \times \rho_w \times (U_{sw})^2)}{2} \quad (2.5)$$

$$S = \tau_m = \frac{(f_m \times \rho_m \times (U_{st})^2)}{2} \quad (2.6)$$

$$S = \tau_o = \frac{(f_o \times \rho_o \times (U_{so})^2)}{2} \quad (2.7)$$

Equations (2.5), (2.6) and (2.7) above are wall shear stresses of water, mixed and oil layers respectively. Subscripts w, m and o means water, mixed and oil respectively..

$$S = \tau_{i1} = \frac{\{(f_{i1} \times \rho_w \times (U_{st} - U_{sw})) \times |U_{st} - U_{sw}|\}}{2} \quad (2.8)$$

$$S = \tau_{i2} = \frac{\{(f_{i2} \times \rho_o \times (U_{so} - U_{st})) \times |U_{so} - U_{st}|\}}{2} \quad (2.9)$$

(Where subscripts i1 and i2 are interfaces of water layer-mixed layer and mixed layer-oil layer respectively).

Mean wall shear stress was then calculated by adding all the wall shear stresses: Equations (2.6) to (2.9) as given below;

$$\tau = \tau_w + \tau_m + \tau_o + \tau_{i1} + \tau_{i2} \quad (2.10)$$

Where τ =wall shear stress (Pa), f = friction factor, ρ = density of fluid, U_{st} = oil-water superficial velocity, U_{so} = superficial oil velocity and U_{sw} = superficial water velocity.

2.6.1 Friction factor

In order to model the friction factor, f , Equation 2.11 derived by using the Fanning friction factor, which for turbulent flow can be approximated [16] was adopted.

The friction factor calculated is valid for Reynolds numbers ranging from 3000 to 3,000,000.

$$f = \frac{(0.046)}{Re^{0.2}} \quad (2.11)$$

Where Re , the Reynolds number, is obtained using equation 2.12 below;

$$Re = \frac{(\rho U D)}{\mu} \quad (2.12)$$

(μ is the dynamic viscosity (Ns/m²), D is the pipe diameter (m) and U is fluid velocity).

The friction factors for the different layers, water, mixed and oil layer were obtained using the Reynolds numbers for the different phases:

$$f_m = \frac{(0.046)}{(Re_m)^{0.2}} \quad (2.13)$$

$$f_w = \frac{(0.046)}{(Re_w)^{0.2}} \tag{2.14}$$

$$f_o = \frac{(0.046)}{(Re_o)^{0.2}} \tag{2.15}$$

The interfacial friction factors f_{i1} and f_{i2} are set as equal to the wall friction factors of the faster phases as shown below [20]:

$$f_{i1} = f_m \text{ and } f_{i2} = f_o$$

According to equation (2.12), the Reynolds numbers defined for each phase as a function of the system temperature are;

$$Re_w = \frac{(\rho_w \times U_{sw} \times D)}{\mu_w} \tag{2.16}$$

$$Re_m = \frac{(\rho_m \times U_{sm} \times D)}{\mu_m} \tag{2.17}$$

$$Re_o = \frac{(\rho_o \times U_{so} \times D)}{\mu_o} \tag{2.18}$$

2.6.2 Density of fluid

Water density as a function of temperature was calculated using the Equation 2.19, which was derived by Gray *et al.*, [17].

$$\rho_w = 1152.3 - 0.5116 \times T \tag{2.19}$$

Where T is temperature in degrees Celsius and density is measured in (Kg/m³) Density of oil was computed using equation (2.20), which was obtained from [18];

$$\rho_o = \rho_{15} \times [1 - 0.0007(T - 15)] \tag{2.20}$$

(Where T is temperature in degrees Celsius and ρ_{15} is oil density at 15°C which was taken as 880kg/m³).

The mixture density was calculated as the weighted average of the two phases based on the hold-up of the dispersed phase, Equation 2.21, [19].

$$\rho_m = (1 - \epsilon_d) \rho_c + \epsilon_d \rho_d \tag{2.21}$$

Where ϵ is water cut or hold-up and subscripts c and d are used for continuous and dispersed phase respectively.

2.6.3 Viscosity of fluid

To calculate water viscosity as a function of temperature, we made use of the expression given by the [20]:

$$\mu = \mu_{ref} \times 10^{\left\{ \frac{(1.3272[20-t] - 0.001053[20-t]^2)}{T + 105} \right\}} \tag{2.22}$$

Where μ_{ref} = reference dynamic viscosity of water at 20°C, whose value is often given as 0.001002 Ns/m² [21], T is absolute temperature (K) and t is temperature in degree Celsius.

For oil viscosity, the modified Ng and Egbogah's correlation (1983) [22] for light crude oil in Nigeria was used as shown in equation (2.23):

$$\mu_{od} = 10^{10(1.67083 - (0.017628 \times API) - 0.61304 \times \text{Log}(T))} \quad (2.23)$$

T is temperature (°F) and API is oil gravity used to describe oil composition and measured in °API. Oil viscosity measured in Centipoise (cP)

To determine the specific gravity of the oil, we made use of the Equation (2.24) [21] given as:

$$SG_{oil} = \frac{(141.5)}{(131.5 + API)} \quad (2.24)$$

$$\text{Where } API = \left(\frac{141.5}{SG} - 131.5\right) \quad (2.25)$$

To calculate the liquid mixture viscosity, Lyons [23] derived the expression shown in Equation (2.26). This was used to calculate the liquid mixture viscosity in this work.

$$\mu_m = \mu_o \left[\frac{1}{(1+WOR)}\right] + \mu_w \left(\frac{WOR}{(1+WOR)}\right) \quad (2.26)$$

Where WOR = water-oil ratio, i.e. water cut and the mixed viscosity is measured in (Ns/m²)

2.6.4 Superficial velocity of fluid

The superficial fluid velocity (m/s) was calculated by dividing the flow rate with the pipe cross section area, A, both for the oil, U_{so} , and water, U_{sw} as shown equations (2.28) and (2.29). The total oil–water superficial velocity, U_{st} is the combined velocity of oil and water used. It was derived by Cai [19] and shown in equation (2.27).

$$U_{st} = U_{so} + U_{sw} \quad (2.27)$$

$$U_{sw} = \frac{Q_w}{A}, \quad (2.28)$$

$$U_{so} = \frac{Q_o}{A} \quad (2.29)$$

Where Q_w = total input volume flow rate of water phase and Q_o = total input volume flow rate of oil phase, which were obtained using Equations 2.30 and 2.31 below:

$$Q_w = Q_{wL} + \epsilon_m Q_m \quad (2.30)$$

$$Q_o = Q_{oL} + (1 - \epsilon_m) Q_m \quad (2.31)$$

Where ϵ_m = water cut in the oil-water mixed layer. ϵ_m at the point of phase inversion ϵ_{invert} was calculated using the expression as given by Arirachakaran [24],

$$\epsilon_m = \epsilon_{invert} = 0.5 - 0.1108 \log_{10} (10^3 \times \mu_o) \quad (2.32)$$

Q_{wL} = pure water layer flow rate, Q_{oL} = pure oil layer flow rate, Q_m = oil-water mixed layer flow rate and μ is oil viscosity. In this work, we assumed Q_m to be given by the relation:

$$Q_m = Q_{wl} + Q_{ol} \quad (2.33)$$

2.7 Predicting the Uninhibited CO₂ Corrosion Rate

With Equation (2.1), we predicted the uninhibited CO₂ corrosion rate (CR_t) along the oil pipeline by inputting the values predicted by models of K_t , fCO_2 , S , and $f(pH)_t$.

2.7.1 Predicting the severity level of the uninhibited corrosion rate

This was done using the categorized severity levels as defined by (Guidelines for Prediction of CO₂ Corrosion in Oil and Gas Production Systems, 2009) [25].

2.7.2 Predicting the life expectancy of the pipeline material

$$\text{Lifetime of pipe material} = \frac{(X - Y)}{CR} \quad (2.34)$$

The life expectancy of the pipeline, measured in years, CR is the calculated corrosion rate in mm/year, where X = pipe material thickness before degradation in mm and Y = minimum allowable pipe thickness during degradation before replacement in mm.

2.7.3 Predicting the mitigated CO₂ corrosion rate

The mitigated corrosion rate (CR) was calculated using equation (2.35) as given by Gartland and Johnsen [26]. This was derived based on the predicted unmitigated corrosion rate and the inhibitor efficiency.

$$CR = CR_{unmit} \times \frac{(100 - IE)}{100} \quad (2.35)$$

CR_{unmit} = unmitigated corrosion rate in mm/year, IE = inhibitor efficiency in percentage.

2.8 Implementation, Simulation and Validation of the Model

Implementation of the models was done using Visual Basic, and a computational software application was created to run under Microsoft windows environment. Figure 2.1 shows the user's interface of the computational CO₂ corrosion rate prediction program; Figure 2.2 shows the CO₂ corrosion rate calculation flowchart;

The simulation input parameters were obtained from the oil company operating the Oil Mining License (OML 61) and were used as input data to simulate corrosion rate along the pipeline and to also analyze the effects of different parameters. The model results were validated against data taken from Nigerian oil and gas industry for pipelines transporting oil and water. To further validate this model, a semi-empirical model for corrosion rate with respect to velocity in the absence of surface scale with a parallel resistance was used [27].

The result of their experimental analysis is summarized in the following expression as;

$$\frac{1}{V_{cr}} = \frac{1}{V_r} + \frac{1}{V_m} \tag{2.36}$$

Where V_{cr} = corrosion rate, V_r = flow independent contribution denoting the reaction rate

V_m = flow dependent contribution denoting the mass transfer rate [27]

$$\text{Log}(V_r) = 4.93 - \frac{1119}{T+273} + 0.58 \log(P_{CO_2}) \tag{2.37}$$

Where T = Temperature ($^{\circ}\text{C}$), P_{CO_2} = CO_2 Partial Pressure (MPa) and

$$V_m = 2.45 \times \frac{(U^{0.8})}{(D_h^{0.8})} \times P_{CO_2} \tag{2.38}$$

Where U = liquid flow rate (m/s) and D_h = hydraulic diameter of the pipe.



Figure 2.1 The User's Interface of the Computational CO_2 Corrosion Rate Prediction Software

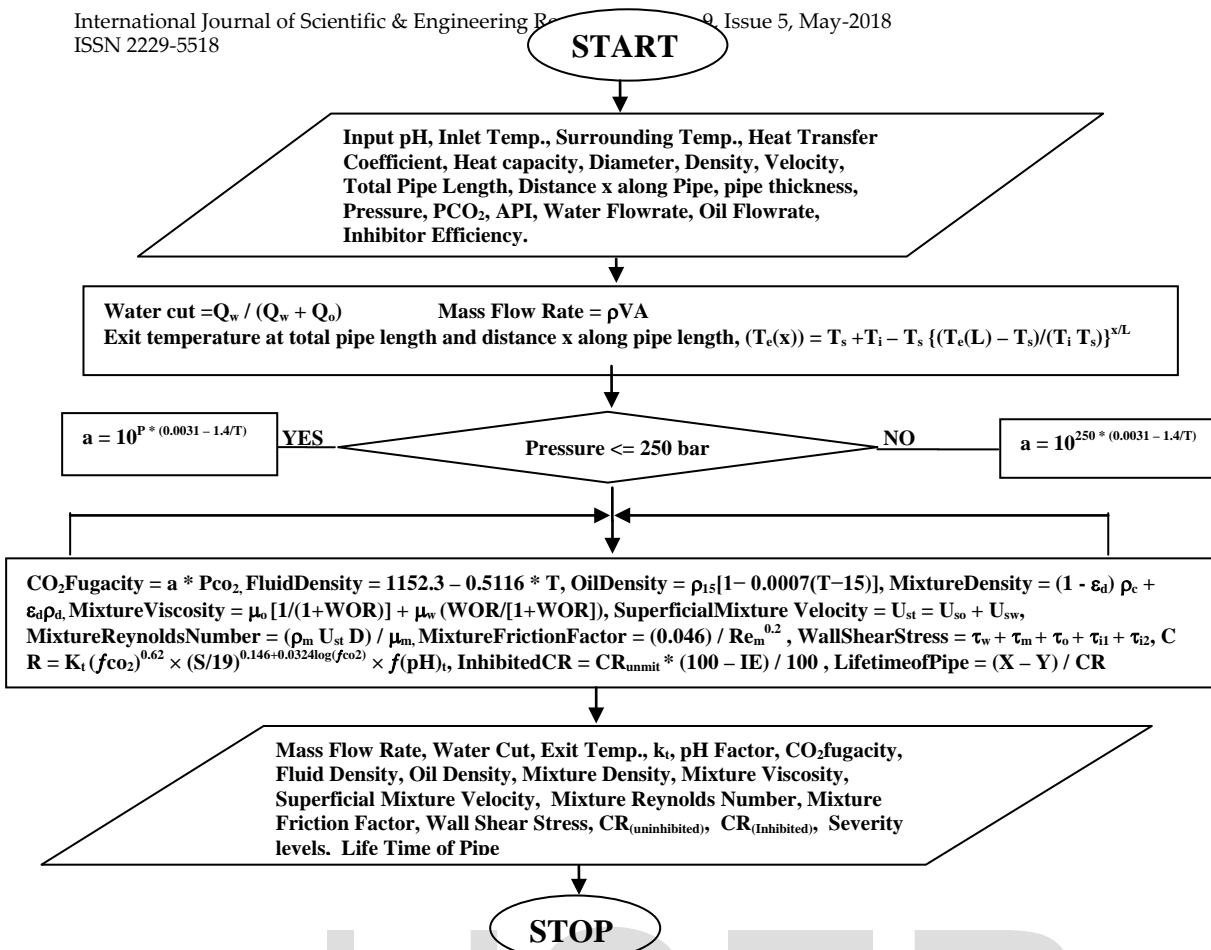


Figure 2.2 The CO₂ Corrosion Rate Calculation Flowchart

3.0 Results and Discussions

The correlation results of the corrosion rate in the pipeline as a dependent variable and temperature along the pipeline distance are shown in figures 3.1 to 3.3.

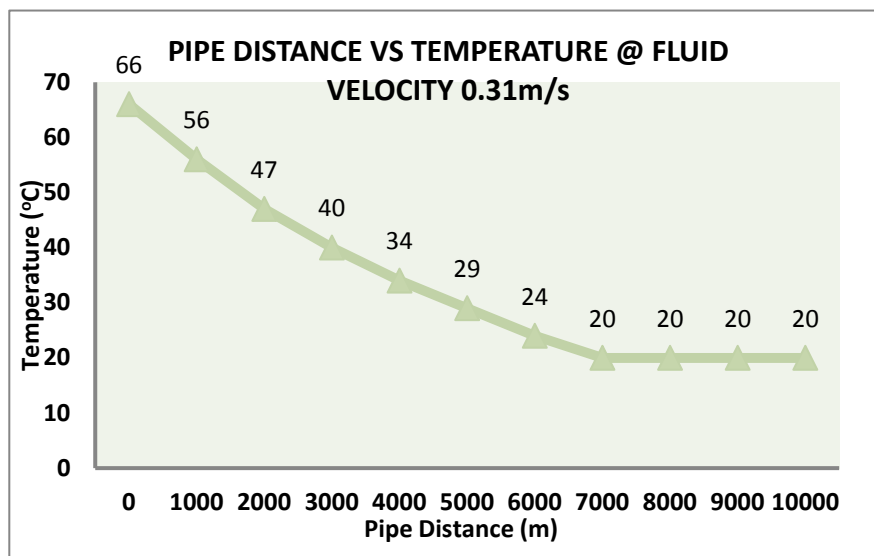


Fig 3.1 Pipe Distance Versus Temperature

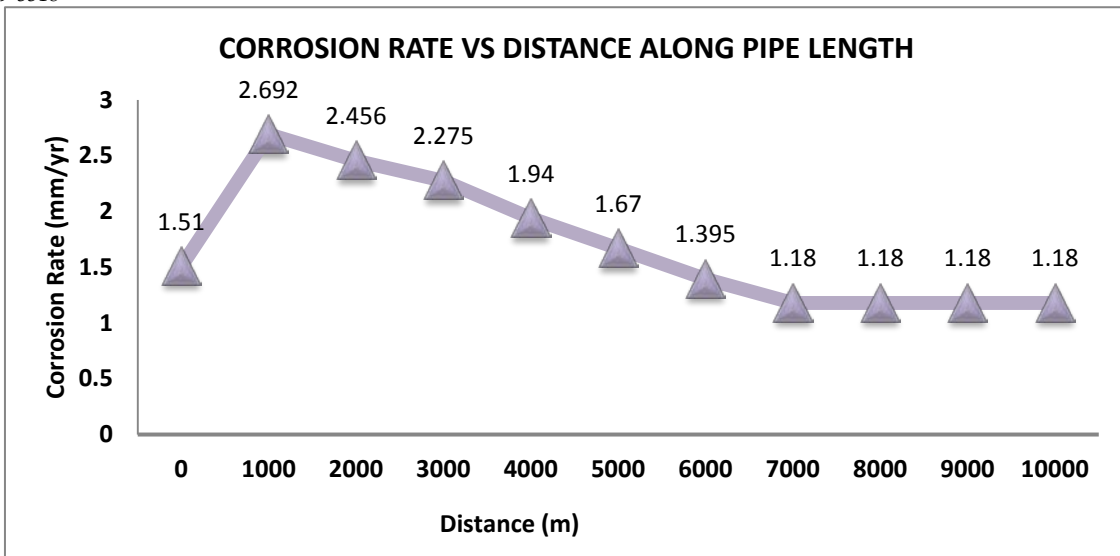


Fig 3.2 Corrosion Rate along the Pipeline Length

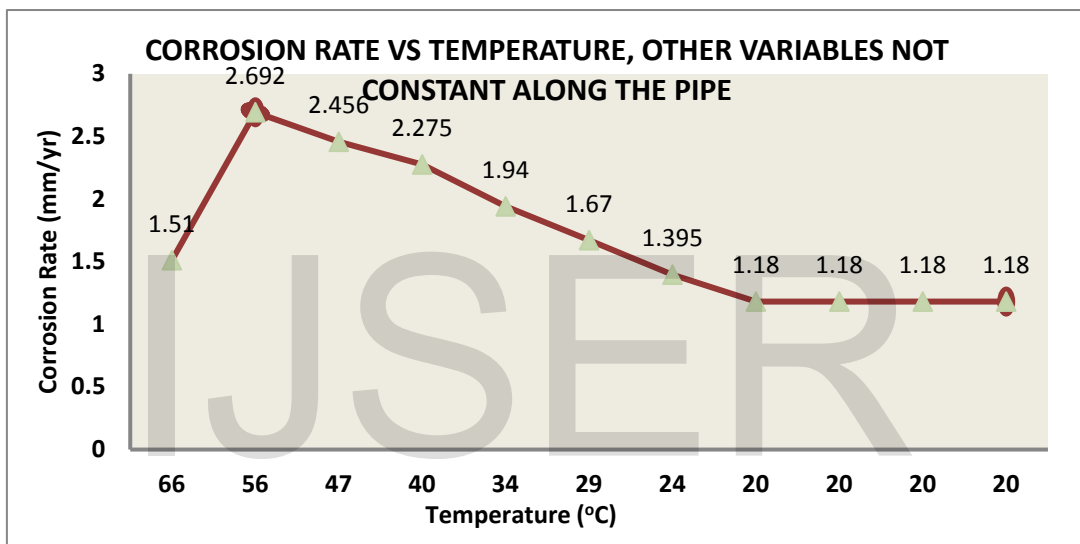


Fig 3.3 Corrosion Rate versus Temperature along the Pipeline Length

It was observed that the temperature gradually decreased as the oil flows through the pipeline, see Figure 3.1. This can be ascribed to the gradual decrease in temperature from inlet temperature at distance (0 metres) due to heat transfer from the heated oil to the surrounding. In isothermal pipelines (where no intermediate heating stations are installed to warm the oil) and in pipelines without heat insulation, the temperature will eventually decline to the surrounding temperature at some kilometers after the inlet point, depending on many factors such as the surrounding temperature, the overall heat transfer coefficient, velocity, and fluid heat capacity [28].

From Figure 3.2, it was noticed that there was a change of corrosion rate as the fluid flowed via the total pipeline length. Also, Figure 3.3 showed a similar result as the temperature was varied with corrosion rate. It was observed that from Figure 3.2 and Figure 3.3, the corrosion rate increased to a

particular temperature and distance (56°C and 1,000 metres in this case) and decreased as the fluid flows over the pipeline distance until it remained constant at a particular temperature and distance (20 °C and 7,000 metres in this case). This is in agreement with the findings of Nestic (2007) who established that the peak in the corrosion rate is usually seen between 60 °C and 80 °C, depending on water chemistry and flow conditions [29].

The modeled result for pipeline corrosion rate was compared with HYDROCOR at different operating conditions; with OML 61 at different temperatures and DE WAARD AND LOTZ model also at different temperatures. The results are shown in figures 3.4 to 3.6.

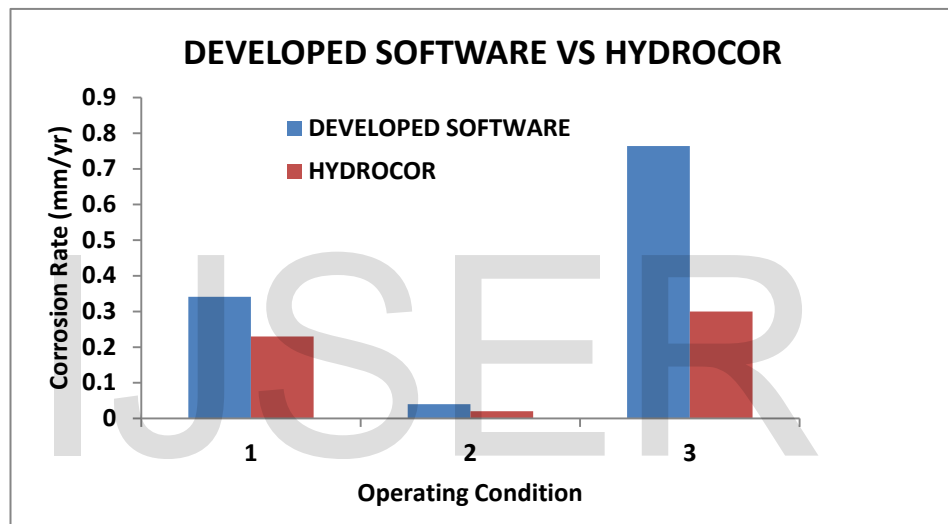


Fig 3.4 Developed Software with HYDROCOR at Different Operating Conditions

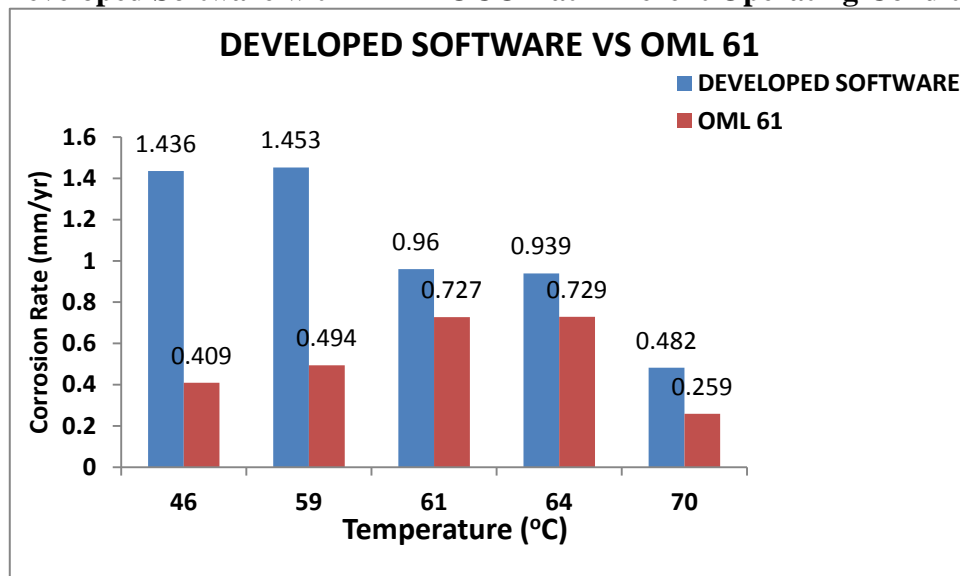


Fig 3.5 Developed Software With OML 61 at Different Temperatures

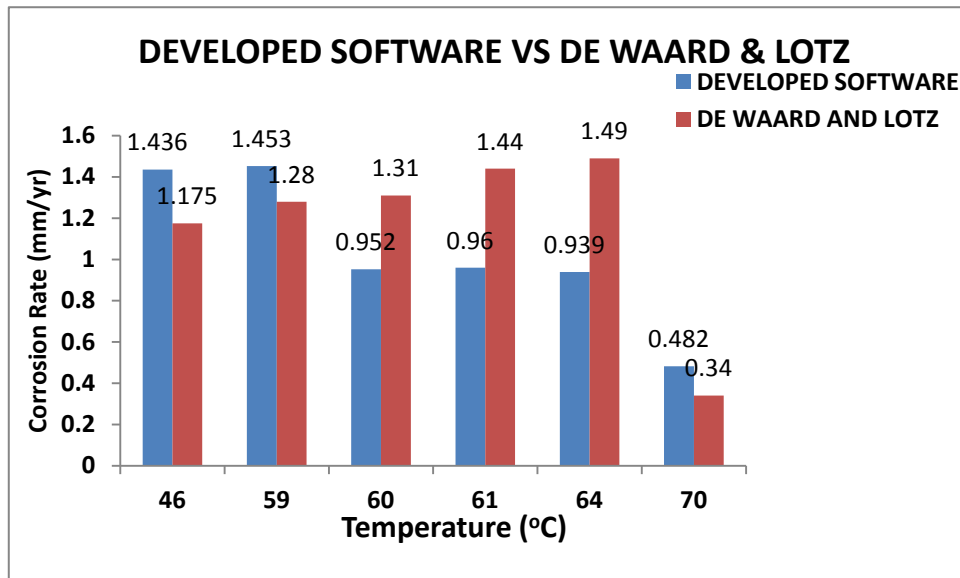


Fig 3.6 Developed Software with DE WAARD AND LOTZ Model at Different Temperatures

Figure 3.4 showed the comparison of the developed software with SHELL’S HYDROCOR. The results are in good agreement. The developed software is an empirical model while HYDROCOR is a mechanistic model. In practice, it is a well known fact that the mechanistic model HYDROCOR is very conservative when it comes to predicting corrosion rate. That is, the model under predicts when compared to other models especially those that do not put into much consideration the physics behind the corrosion just as mechanistic models do.

To ascertain the statistical accuracy of the predicted values, standard error (SE) calculation was performed. HYDROCOR had a SE of 0.08 while the developed software had a SE of 0.2. Also, in order to ascertain the reliability of the predicted values, confidence interval (CI) calculation was carried out. At confidence level of 90%, HYDROCOR had a confidence interval between 0.04 mm/year and 0.32mm/year. This is to say that at 90% confidence level, it can be said, we are 90% confident the mean corrosion rate is between 0.04 and 0.32mm/year. At the same confidence level of 90%, the developed software had a confidence interval between 0.04 and 0.73 mm/year. This is to say also that at 90% confidence level, it can be said, we are 90% confident the mean corrosion rate predicted is between 0.04 and 0.73mm/year.

Furthermore, the developed software prediction was compared with operating field data obtained from a Nigerian oil and gas company (OML 61). The results obtained are shown in Figure 3.5. To ascertain the accuracy of the model prediction, the average percent error (APE) and average absolute

percent error (AAPE) of the data source used were calculated. The APE is used to quantify the degree of over prediction or under prediction of the experimental data. Positive values indicate over prediction while negative values indicate under prediction. AAPE is used to evaluate the prediction capability of the model. The lower the value of AAPE; the better the precision of the calculated values that can be achieved from the model. The APE for the developed software was 19.74%, meaning the model over predicted compared to the operating field data. Often times, predicted values and measured values are never exactly the same. The developed software also had an AAPE of 19.74%. This value cannot be said to be accurate or not since the range of percentage error where it is regarded as accurate or not accurate is a function of application.

To measure the statistical accuracy of the predicted values, SE was calculated. The developed software had a SE of 0.18. To determine the reliability of the predicted values, confidence interval (CI) was calculated. At 95% confidence level, the developed software had a CI between 0.70 and 1.41 mm/year. This means that we are 95% confident that the mean corrosion rate predicted is between 0.70 and 1.41 mm/year.

For the sake of more comparison using the same operating field data, the De Waard and Lotz semi empirical model was employed, see Figure 3.6. The Waard and Lotz semi empirical model had an APE of 19.34%, AAPE of 19.34%, SE of 0.21 and confidence interval (CI) at 95% confidence level of between 0.74 and 1.55 mm/year. Comparing the developed software with De Waard and Lotz model, we had a good agreement as depicted by Figure 3.6. From the statistical analysis results mentioned earlier for both models, we could see that both models over predicted having a positive APE value; statistical accuracy of predicted values of this model was better when compared with De Waard and Lotz; and the reliability of the predicted values at 95% confidence level of both models were between 0.7 and 1.41mm/year for this model and 0.74 and 1.55mm/year for De Waard and Lotz model.

4.0 Conclusion

A computer software for determining the corrosion rate of oil pipelines in CO₂ environment using modified NORSOK M-506 model has been developed. The NORSOK M-506 model has been

modified to include a temperature distribution model that predicts the temperature at any point along the oil pipeline. The wall shear stress parameter which is a function of flow related parameters (viscosity, density, friction and velocity) of the NORSOK M-506 model has also been modified to suit the light crude oil of the Nigerian oil and gas industry.

The entire model has been successfully implemented using an enhance-able; user friendly Visual BASIC to create a computational software that can run under any Microsoft windows.

Simulation and validation of the model was carried out. The simulation and validation results showed an acceptable agreement. The validation done by comparing the model with SHELL'S HYDROCOR and De Waard and Lotz models was satisfactory, as this model recorded an acceptable agreement with the mechanistic and semi empirical models of HYDROCOR and De Waard and Lotz. The developed computational software is user friendly and has a computation time of less than one minute for the user to input data and see the output.

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