Scientia Africana, Vol. 13 (No.1), June 2014. Pp 77-88
 ISSN 1118 - 1931

ANALYTICAL MODELING OF PIPELINE FAILURE IN MULTIPHASE FLOW DUE TO CORROSION IN NIGER DELTA REGION

P. Ofoeyeno, U. Osokogwu and A. B. Oriji
Department of Petroleum and Gas Engineering,
University of Port Harcourt, Port Harcourt, Nigeria

Received: 11-04-14
Accepted:05-05-14

ABSTRACT
Pipeline could be said to be the safest and the most economical means of transportation of hydrocarbon fluids. Pipelines carrying oil and gas may suffer from internal corrosion when water is present. The corrosivity varies due to several factors such as; temperature, total pressure, CO_2 and H_2S content in the gas, pH of the water, flow conditions, inhibiting chemicals etc. Corrosion, when not properly dealt with could lead to pipeline integrity issues which will be very uneconomical for the operator company. This research focuses on the development of a model that can predict pipeline failure due to corrosion in multiphase flows. The role that velocity, density, water cut and other parameters play in predicting corrosion is critically analyzed with Norsok Model. The result shows that velocity plays a key role in corrosion prediction.Increasing oil velocity from 0.1 to 1.25 m/s leads to an increase of corrosion rate from 1.67 to 5.58 mm/yr. This is because at the selected pH of 4, the corrosion rate is very sensitive to mass transfer and turbulent mixing which are in turn enhanced at higher flow rates.

INTRODUCTION
Pipeline could be said to be the safest and the most economical means of transportation of hydrocarbon fluids. Pipeline as discussed here includes the flowlines from producing wellheads to the flowstations, trunk lines which transport the produced hydrocarbons from the flowstations to the storage terminals or from the Refineries to the Depots and/or jetties; and pipeline (loading lines) through which oil and gas are transported to the off take tanker.

Pipelines carrying oil and gas may suffer from internal corrosion when water is present. The corrosivity will vary in dependence of many factors such as the temperature, total pressure, CO_2 and H_2S content in the gas, pH of the water, flow conditions, and inhibiting chemicals, etc. In order to maintain integrity, production pipelines are subject to intelligent pig inspection at certain time intervals. Predicting the failure of damaged oil and gas pipeline has become an essential art for the determination of design tolerance. (Stein, 2003).Corrosion is the deterioration or destruction of a metal by chemical and electrochemical reaction with its environment. It can be found on metal such as steel and non-metal like ceramic and plastic. Corrosion adversely affects human, environment and also the properties of the metal itself (Xiao, 2005). Corrosion is one of the main reasons for pipeline replacements. External and internal corrosion causes degradation of pipes made of grey cast iron, ductile iron and steel. The internal corrosion depends on the characteristics of the transported water (e.g. pH, alkalinity, bacteria and oxygen content) and external corrosion depends on the environment around the pipe (e.g. soil characteristics, soil moisture, and aeration), Pots, (1995).

Fig. 1: *Internal corrosion of a crude oil pipeline*

There are other numerous methods of determining the rate of corrosion depending on the type of corrosion, environment and the method of analysis.

Fig. 2: *Corrosion in oil/gas pipeline*

Pipelines transporting oil and gas are vulnerable to internal corrosion when water forms a part of the transported fluids. The presence of carbon dioxide (CO_2) in the fluid accelerates the corrosion rate due to its reaction with water which results in forming carbonic acid, and hence, water pH is reduced. The corrosion rate prediction is an important task needed to manage and control the corrosion. Several prediction models have been developed for CO_2 corrosion of oil and gas pipelines (Nyborg 2002). The models are correlated to different laboratory data and, in some cases, also to field data from the individual company. Most of the models cannot be used in situations where H_2S or organic acids dominate the corrosion process.

- Predicting pipeline failure in multiphase flow where fluid velocity plays a prominent role has not been thoroughly modeled especially in the Niger Delta.
- The role of velocity, density, water cut and other parameters needed to be

Scientia Africana, Vol. 13 (No.1), June 2014. Pp77-88
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analyzed in predicting corrosion rate using Norsok Model.
- Prediction of CO_2 corrosion in pipelines needs to be resolved.

The inherent uncertainties embedded with metal-loss data plays significant roles in reducing the accuracy of pipeline future assessment and its integrity, hence,the objective of this project is to analytically model pipeline failure criteria that can be used to predict corrosion rate in multiphase flow.

The main benefits of this research are:
- To have a model that can achieve accurate prediction of failure in corroded pipeline in Niger Delta.
- To know the effect of various parameters that affect multiphase flow in oil and gas pipelines which can lead to accurate failure prediction of corrosion rate.

Dayalan et al. (1995) proposed a mechanistic model for the carbon dioxide corrosion of steel in pipe flow. They suggested that the overall corrosion process can be divided into four steps. The first step is the dissolution of carbon dioxide in the aqueous solution to form the various reactive species which take in the corrosion reaction. The second step is the transportation of these reactants to the metal surface. The third step involves the electrochemical reactions (anodic and cathodic) taking place at the surface. The final step is the transportation of the corrosion products to the bulk of the solution. A variety of models for internal corrosion of mild steel oil and gas pipelines carrying multiphase flow (mixture of oil, gas and water) has appeared over the past thirty years following the pioneering attempts of deWaard and Milliams in 1975. In a 2002 paper, Nyborg reviewed the performance of a representative group of models concluding that most of the models predict successfully the "worst case" CO_2 corrosion rate but vary widely when more complex effects are included (e.g. protective scales, water entrainment/wetting, H_2S, etc).

MATERIALS AND METHODS

Norsok Model

The Norsok model is an empirical model mainly based on laboratory data at low temperature and a combination of laboratory and field data at temperatures above 100 °C. The model has been developed by the Norwegian oil companies Statoil, Norsk Hydro and Saga Petroleum, and has been issued as a standard for the Norwegian oil industry. The spreadsheet with the model is openly available. The model is fitted so much of the same IFE laboratory data as the de Waard 95 model, but includes in addition more recent experiments at 100 - 150 °C. The model takes larger account for the effect of protective corrosion films and therefore predicts lower corrosion rates at high temperature and high pH than the de Waard model. The model is considerably more sensitive to variation in pH than the de Waard model. The model does not account for any effect of oil wetting. The model takes temperature, total pressure, CO_2 content, pH, wall shear stress and glycol concentration as major input. The model contains modules for calculating pH and wall shear stress. Three options for calculating pH are available. For condensed water without corrosion products the pH is given by the temperature and CO_2 partial pressure. The pH in condensed water saturated with iron carbonate produced by corrosion can also be calculated. For formation water the pH calculation is based on a specified bicarbonate content and ionic strength from a water analysis. Wall shear stress can be calculated from production rates and pipe diameter (Nyborg 2002).

Predict model

The Predict model is developed by InterCorr International (formerly CLI International). The basic part of the model is based on the de Waard model, but other correction factors are used together with a so-called effective CO_2 partial pressure calculated from the system pH. The model includes very strong effects of oil wetting and protective corrosion films, and this tends to give very low corrosion rates for many situations. The model takes temperature, CO_2 and H_2S partial pressure and flow velocity as major input. The pH value can either be given as an input or calculated from the bicarbonate content and ionic strength or full water chemistry. The model includes a simplified flow modeling module for calculation of flow velocity and flow regime. For low gas/oil ratios the model asks for the water cut in order to predict oil or water wetting and distinguishes between persistent and not persistent oil types. Low corrosion rates are typically predicted when the water cut is below 50 % for highly persistent oils and 5 % for not persistent oils. For high gas/oil ratios the model asks for the dew point in order to calculate water condensation. The model has a very strong pH dependence on the corrosion rate, due to both effect of protective corrosion films and effect of H+ mass transport limitations. This tends to give low corrosion rates when the pH value is higher than 4.5 to 5 (Nyborg 2002).

Modeling Multiphase Corrosion Rate

During oil's transportation, temperature gradually decreases from the inlet temperature (at 0 km distance) due to heat transfer from theheated oil to the surroundings. In isothermal pipelines (where no intermediate heating stations are installed), the temperature will eventually decline to the surrounding temperature 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. The temperature at distance L along the pipeline can be calculated using the following equation;

$$T_L = T_0 + (T_i - T_o)e^{-\left(\frac{K_{tot}\pi D}{Gc}\right)L} \qquad (1)$$

where, T_i is the inlet temperature, T_o is the surrounding temperature, K_{tot} is the overall heat transfer coefficient (a function of the fluid heat convection factor and the pipe and coating heat conduction factor), c is the heat capacity of the fluid. G is the mass flow rate of the fluid kg/s, which is related to fluid velocity as follows:

$$G = \frac{\pi}{4} D^2 V \rho_f \qquad (2)$$

where ρ_f is the fluid density, V is the fluid velocity and D is the pipe diameter.

Corrosion rate is a function of temperature, so that different points along the pipeline are expected to corrode in different rates depending on the temperature at the specified point.

According to NORSOK model, Eq. 3, CO_2 corrosion occurs within temperature range of 20 to 150ºC can be calculated using the following empirical equation:

$CR_t = K_t \text{ x } f_{CO2}{}^{0.62} \text{ x } (S/19)^{0.146 + 0.0324 \log (fCO2)} \text{ x } f(pH)_t$ (mm/year)(3)

The following equation is used at temperature 15 °C:

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$CR_t = K_t \times f_{CO2}^{0.36} \times (S/19)^{0.146 + 0.0324 \log (fCO2)} \times f(pH)_t$ (mm/year) (4)

The following equation is used at temperature 5 °C:

$CR_t = K_t \times f_{CO2}^{0.36} \times f(pH)_t$ (mm/year) (5)

Where K_t is a temperature-related constant its values are listed in table 1 for temperatures ranging from 5 to 150ºC and f(pH) is a factor depending on the pH of the solution. NORSOK model introduced a list of empirical models for calculating this factor at different temperatures and ranges of pH as shown in table 2.

Equation (1) is used to calculate temperature distribution along the pipe assuming constant overall heat transfer coefficient and surrounding temperature. The calculated temperatures can then be used to calculate shear stress, fugacity, pH, and k_t at the respective points, and hence, corrosion rates are calculated using Eqs. (4-5).

From Eqs. (3-5), CO_2 corrosion depends on four factors which also depend on temperature. These factors can be summarized as shown in Table 1.

Table 1: The Effect of Four Parameters along the Pipeline

Parameter		Effect of temperature	The expected change along pipeline
K_t	Temperature-dependant constant	Increases from 5 to 60ºC and then decreases up to 150ºC	Decreases with distance
fCO_2	Fugacity of CO_2	Decreases with temperature	Decreases with distance due to stronger dependency on system pressure (P) which decreases along the pipeline (The CO_2 partial pressure (P_{CO_2}) is assumed constant). $fCO_2 = a \times P_{CO_2}$ $a = 10^{P(0.0031-1.4/T)}$
S	Wall shear stress	Increases with viscosity and density which in turn decreases with temperatures.	Increases with distance
$f(pH)_t$	The effect of pH at any temperature	As tabulated by NORSOK	Increases with distance

Sources: Norsok Standard M-506

To calculate the fugacity of CO_2 (fCO_2), the total system pressure is calculated along the pipeline.

$f_{CO2} = a x p_{CO2}$(6)

The CO_2 partial pressure is found by one of the following expressions:

p_{CO2}=(mole%CO_2 in the gas phase/100 %) xPor**(7)**

$$pCO_2 = \frac{\text{mass flow of } CO_2 \text{ in the gas phase (kmole/h)} \times P}{\text{total mass flow in the gas phase (kmole/h)}} \quad (8)$$

The fugacity coefficient is given as

$a = 10^{P \times (0.0031 - 1.4/T)}$ for $P \leq 250$ bar

$a = 10^{250 \times (0.0031 - 1.4/T)}$ for $P > 250$ bar

The total pressure is set to 250 bar in the fugacity constant for all pressures above 250 bars.

Darcy-Weisbach equation is used to calculate friction pressure losses within every interval. The Reynolds number and friction factor in any interval are calculated using the fluid density and viscosity at the temperature at that interval.

The density and viscosity of water at any temperature T is calculated as follows (assuming the water density at 20°C is 999.2 kg/m3):

$$\mu_w(T) = ((T + 273) - 225.4)^{-1.637} \quad (9)$$

$$\rho_w(T) = \frac{980}{(1+0.0002(T-20)} \quad (10)$$

The oil density at any temperature T is calculated as follows:

$$\rho_o(T) = \rho_{20} - (1.825 - 0.001315\rho_{20})(T - 20) \quad (11)$$

where ρ and μ are density (kg/m3) and viscosity (cp) and the subscripts o and w denote oil and water respectively and ρ20 (kg/m3) is the oil density at 20°C.

Beggs and Robinson correlations are used for viscosity prediction at any temperature T.

These correlations are as follows:
The viscosity, $\mu_o(T)$, at temperature, T, is given as

$$\mu_o(T) = 10^{y(\frac{9T+160}{5})^{-1.165}} - 1 \quad (12)$$

$$y = 10^{3.0324-0.02023G} \quad (13)$$

where G is the API gravity of the oil which can be obtained from correlations as follows:

$$API = \frac{141.5}{SG} - 131.5 \quad (14)$$

The mixture density and viscosity at any temperature T is calculated as follows:

$$\frac{1}{\mu_m(T)} = \frac{(WC/100)}{\mu_w(T)} + \frac{(1-WC/100)}{\mu_o(T)} \quad (15)$$

$$\rho_m(T) = \rho_w(T) \times \frac{WC}{100} + \rho_o(T) \times (1 - \frac{WC}{100}) \quad (16)$$

Where WC is water cut (%)

The mixture viscosity and density is then substituted in the following formula to calculate Reynolds number at the temperature T

$$Re(T) = \frac{\rho_m(T)VD}{\mu_m(T)} \quad (17)$$

Where V is the flow velocity (m/s) and D is the pipe diameter (m).
In the case of laminar flow (Re (T) ≤ 2000), the friction factor is calculated as follows

$$f(T) = \frac{16}{Re(T)} \quad (18)$$

In the case turbulent flow regime (Re (T) > 2000), friction factor is calculated using Churchill model as follows

$$f(T) = 2\left[\left(\frac{8}{Re(T)}\right)^{12} + (A + B)^{-1.5}\right]^{1/12} \quad (19)$$

Where A, B, and c are given in Eqs. (20)-(21)

$$A = \left[2.457 \ln\left(\frac{1}{c}\right)\right]^{16} \quad (20)$$

$$B = \left(\frac{37530}{Re(T)}\right)^{16} \quad (17) \qquad c = \left(\frac{7}{Re(T)}\right)^{0.9} + 0.27\frac{e}{D} \quad (21)$$

and e is the pipe roughness (m).
The friction factor is introduced to Darcy-Weisbach equation as follows to calculate the pressure losses drop (ΔP_f) in Pascal as follows:

$$\Delta P_f(T) = 4f(T)\frac{\Delta L}{D}\rho_m(T)\frac{V^2}{2} \quad (22)$$

where ΔL is the pipe length (m).

The wall shear stress (in Pascal) at any temperature T is calculated using the following equation:

$$S(T) = \frac{f(T)\rho_m(T)V^2}{8} \quad (23)$$

Although the pH factor can be read from the table 2, calculation can also be used to evaluate factor.

In multiphase systems, where formation water is present, the dissolved salts act to

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buffer the pH. If the water pH is higher (less acidic) than would be the case with no buffering agent present, then the rate of corrosion will be reduced.

A pH factor can be calculated from the empirical formula:

$$\log F(pH) = -0.13(pH_{measured} - pH_{calculated})^{1.6} \quad (24)$$

Where the calculated pH is derived from:

$$pH=3.71-0.5.\log(pCO2) + 0.00471T \quad (25)$$

RESULTS

Data Analysis and Presentation

The parameters in Table 4 were taken from a pipeline in the Niger Delta as input data to predict corrosion rate along the pipeline and analyze effects of different parameters.

Table 2: Input Parameters for Developed Model

Parameter	Unit	Value
Velocity	m/s	0.1, 0.3, 0.5
pH	-log (H^+) conc.	5
Inlet temperature	^oC	70
Surrounding temperature	^oC	20
Overall heat transfer coeff.	$W/m^{2o}C$	2
Heat capacity	J/kgm^2	3400
Water cut	%	70
Total length of pipe	km	100
Oil density at 20^oC	Kg/m^3	800
Pipe Diameter	m	0.2
Roughness	m	0.0005
Temperature related constant	K	4.762

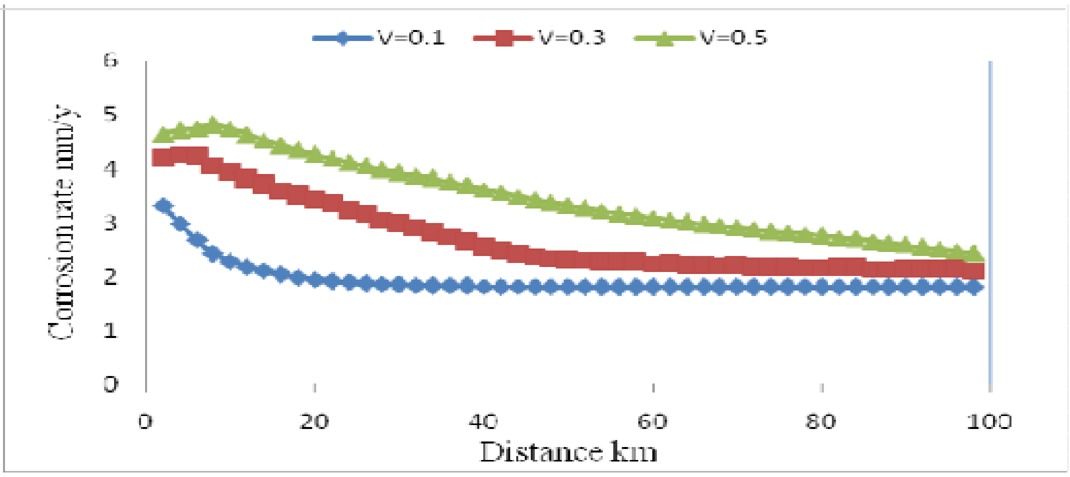

Fig. 3: Corrosion Rate along Pipeline at Different Velocities

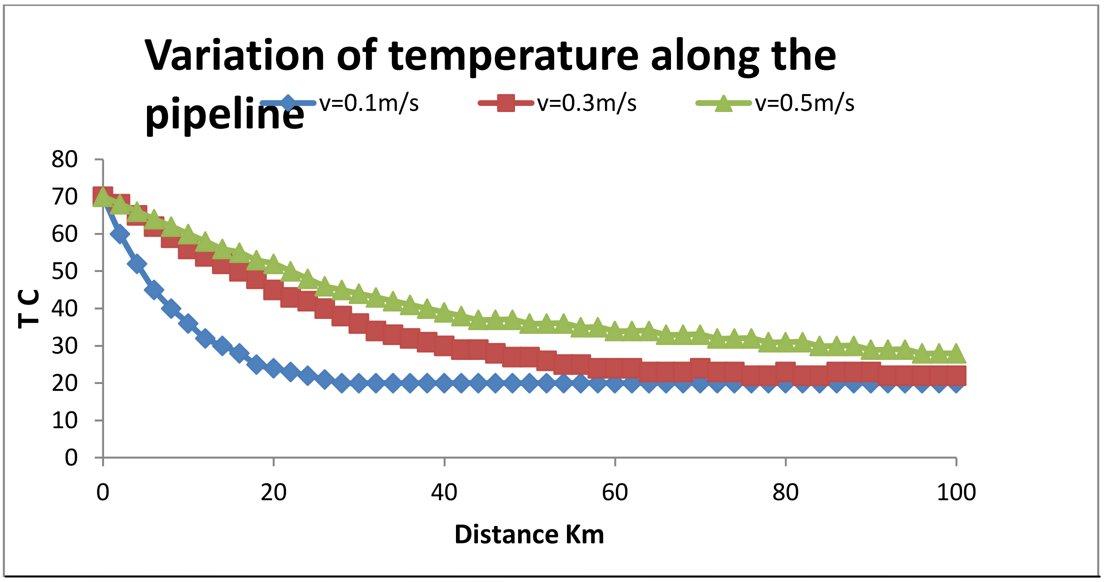

Fig. 4: Variation of Temperature along Pipeline at Different velocities

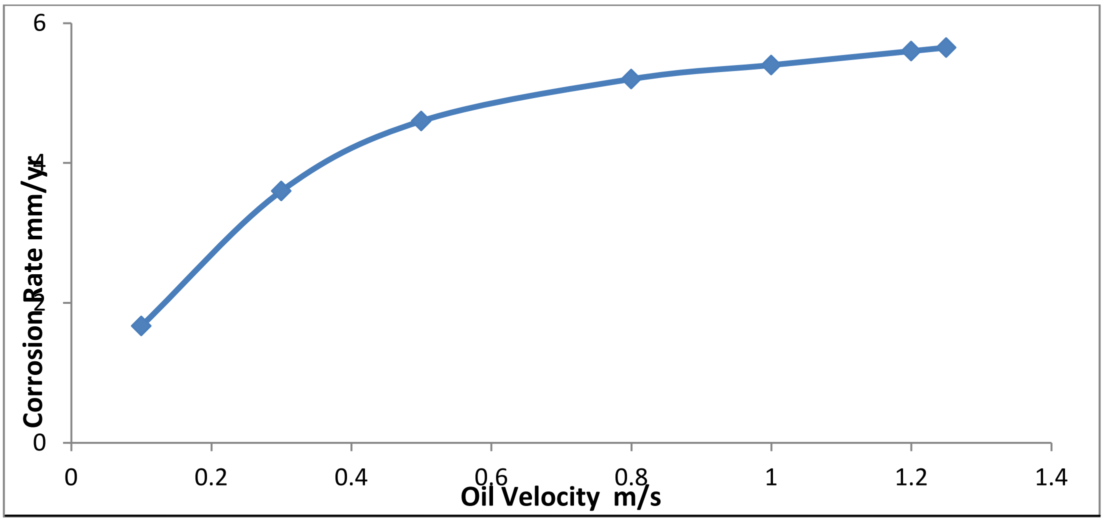

Fig. 5: Relationship between corrosion rate and oil velocity at pH= 4

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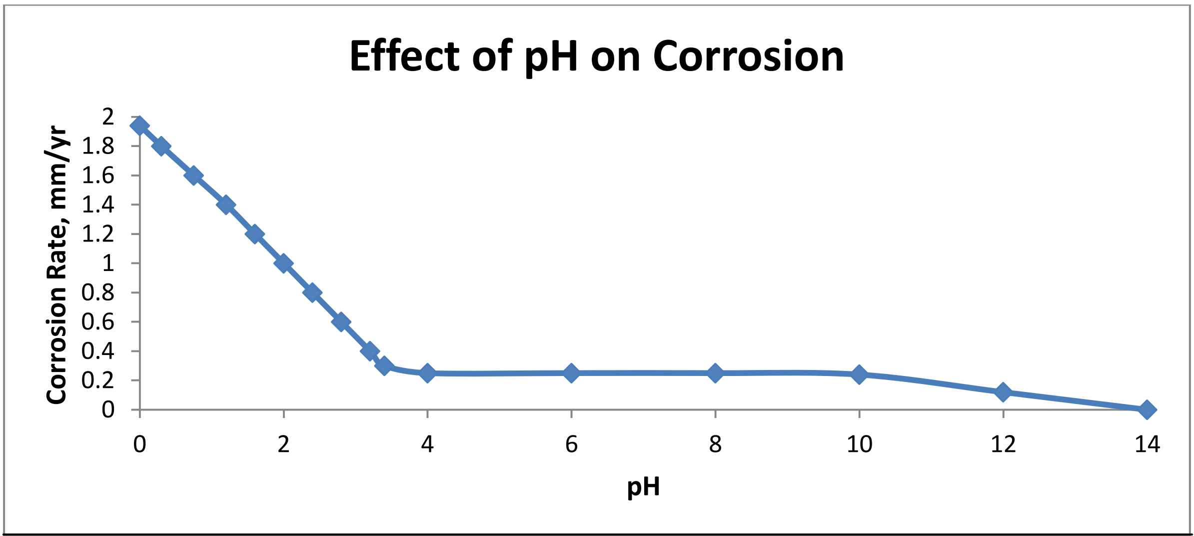

Fig. 6: The Effect of pH on General Corrosion Rate

Table 3: Corrosion rate constant (K_t)

Temperature °C	K_t
5	0,42
15	1,59
20	4,762
40	8,927
60	10,695
80	9,949
90	8,250
120	7,770
150	5,203

Table 4: Corrosion Profile along the Length of a Pipe using the proposed model

Corrosion Rate (mm/y)	Pipe Length (m)
0.38	0
0.39	60
0.4	90
0.41	140
0.42	200
0.43	250
0.44	270
0.45	340
0.46	420
0.47	500
0.49	590
0.5	695
0.51	750
0.53	810
0.6	860
0.62	930
0.64	1000
0.67	1105
0.7	1195
0.72	1250
0.74	1330
0.77	1410
0.8	1680
0.83	1830
0.86	2000
0.88	2360

With the points taken at interval of 2km and at different velocities as shown in the fig. 3, shows the variation of corrosion rate along the pipeline at different flow velocity. It is clear that the corrosion rate decreases along the pipeline. The degree of declination is, however, decreases with the increase of flow velocity. This is because of the fact that at higher velocity more heat is generated which compensates part of the heat lost due to heat transfer between the transported fluid and surroundings. That is to say, higher velocity leads to higher temperature as compare to that result from lower velocity. As temperature, normally, increases corrosion rate, less declination of corrosion rate results from higher velocity, (Nesic, 2005).

The variation of temperature along the pipeline using the same input data is shown in Fig. 4. At flow velocity of 0.1 m/s temperature declines very fast to reach the surrounding temperature at 36 km and remain constant. Therefore, the corrosion rate at this velocity, from fig.3, reaches the minimum value at this distance and remains constant until the pipeline terminal.

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From the model results, it was found that corrosion rate always decreases along the pipeline. It also shows that the contribution of the corrosion-related parameters predominates over the effect of flow-related parameters. The model results will be validated against published field data.

Fig.5 shows the relation between corrosion rate and oil flow rate at pH= 4 in oil-water horizontal flow. This demonstrated the effect of velocity on corrosion rate as predicted by this model. Increasing oil velocity from 0.1 to 1.25 m/s leads to an increase of corrosion rate from 1.67 to 5.58 mm/yr.

The corrosion-related parameters like pH decreases with temperature decreases which leads to decrease of corrosion rate along the pipeline. Fig.6 shows the influence of pH on corrosion rate along a pipe where the developed model was used to establish the relationship between corrosion rate and the pH of the water flowing with fluid in the multiphase flow.

Norsok standard CO_2 corrosion prediction model was coupled to pipelines thermal and fluid flow calculation models to simulate CO_2 corrosion rate along pipelines. A computational program was also developed to predict the corrosion rate and its affected factors along the pipelines at any conditions. Pipeline operation parameters were used as input data and the results were analyzed at three flow velocities. It has been found that, flow velocity is markedly affecting the variation of thermal and fluid flow characteristics which in turn affects the corrosion rate along the pipeline. At low velocities, temperature declines rapidly to reach the surrounding temperature short distance after the pipeline inlet to remain constant until the terminal point. At high velocities the temperature, most probably, remains above the surroundingtemperature until the terminal point.

The variation of temperature along the pipeline has double effect on the corrosion rate variation along the pipeline. The flow related parameters (viscosity and density) increases with the temperature decrease. This leads to increase in shear stress along the pipeline which turns in increasing corrosion rate. The corrosion-related parameters (Kt, CO_2 partial pressure and pH) decreases with temperature decreases which leads to decrease of corrosion rate along the pipeline.

It was found that corrosion rate always decreases along the pipeline, showing that the contribution of the corrosion-related parameters predominates over the effect of flow-related parameters.

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