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MODIFIED CO_2 CORROSION MODEL TO MINIMISE CORROSION LIMITED LIFETIME COSTS OF PETROLEUM PIPELINES

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Abstract: In order to ensure safe operation and prevent environmental damage of petroleum pipelines with limited lifetime cost, it is very important for designers, engineers and field operators to be aware of corrosion. Pipeline structures can experience material degradation caused by corrosion. This research study presents results from the development of a model to determine the minimum corrosion limited lifetime cost of a petroleum pipeline. It focuses on internal corrosion of carbon steel pipes caused by the presence of CO_2. A mathematical model was developed by modifying the NORSOK M-506 corrosion model which was then used to predict CO_2 corrosion rate profile along a horizontal pipeline at different intervals. The Overall heat transfer Coefficient per unit area (U), was defined to consist of thermal conductivity of pipe material (K), heat transfer coefficient of the fluid (h_o) and surrounding air (h_a), and the pipe thickness (d_{xw}). Sensitivity analysis was carried out for each parameter to determine their effects. Field data set for a 24 inch horizontal petroleum pipeline with total length of 10,000 m was used to predict the corrosion rate profile at intervals of 500 m along the pipeline. The result obtained was similar to real test result. The corrosion rate was used to determine the life expectancy and lifetime cost of the pipe structure. Same process was repeated using six different pipe sizes. It was discovered that corrosion rate along a pipeline at same interval does not decrease linearly. Findings show that larger pipe diameter presents lesser corrosion rate than the small diameter pipes for the same operating condition. However, proper analysis and size selection do not depend only on the life expectancy of the pipe but also a feasible cost which is an effective factor to be considered.

Keywords: Corrosion model; Pipeline failure; NORSOK M-506.

INTRODUCTION

Corrosion in general is a frequent problem encountered in the transportation of petroleum products through pipelines. This is as a result of the presence of corrosive components such as H_2S and CO_2. It has been identified that corrosion is one of the major causes of pipeline failure [1]. Environmental damage, risk to human health and loss of integrity are some of the major effects encountered by pipeline failure. Pipelines are susceptible to corrosion by exposure to the environment, either buried in the soil or submerged in water. Corrosion accounts for18% of the significant incidents both offshore and onshore installations [2].

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Production, storage and transportation of petroleum products encounter some challenges in the oil and gas sector and corrosion is one of the major problems. Controlling such problem effectively can extend the life expectancy of infrastructures. The increased risk associated with pipeline failure overshadows the cost related to the project itself. Ref. [3] in a review concluded that the principle of corrosion should be well understood in other to select the appropriate material for design and construction. This should be utilized to achieve an optimum economic life of the infrastructure and safety during operation. This should come into play by the design engineer in the early stage. On the other hand, mitigation, management and control of corrosion are also essential during the lifetime operation of the infrastructure. Technical methods which are used to reduce the effect of corrosion during operation include coatings and linings, use of inhibitor, anodic and cathodic protection, as well as design improvement [4].

In other to determine the life expectancy of a pipeline, the rate at which the pipe material will degrade mostly depends on corrosion. The presence of CO_2, H_2S, water and chloride contents are responsible for corrosion. Simulating CO_2 corrosion rate along a pipeline can be a challenging effort in the petroleum industry, and as a consequence a number of prediction models have been developed. The most important problems and key factors that complicate this study include the following:

- Variation of temperature or temperature profile along a horizontal petroleum pipeline not fully understood. This was as a result of incomplete availability of data set which includes the thermodynamic properties of the fluid and the pipe material.
- Cost effective choices been made when selecting a pipe size for the purpose of life expectancy and safe operation.

This work involves developing a model that will minimize corrosion limited lifetime cost of a petroleum pipeline. The study presents concise information on how to select a pipe size by assessing the life expectancy of a pipeline, the gaps in current knowledge, and the direction of current research and development. While this work does not broadly address sour corrosion (due to the presence of H_2S), it does highlights the CO_2corrosion rate along a pipeline with reference to prediction models while being discussed. The research will be applied to a particular case study for the discussion of our findings.

In other to achieve the aim of this study, the key objectives which this work intends to focus on are:

- To predict the CO_2 corrosion rate along the pipeline for a chosen case study

- Determine the life expectancy of the pipeline
- Determine the assessed value of the pipeline.

METHODOLOGY

In order to carry out this research, a methodology was developed by adopting a proprietary mathematical model as the key tool. A CO_2 corrosion model was built by modifying the NORSOK M-506 model to predict the corrosion rate at different distance along the pipeline. This model (NORSOK M-506) was chosen due to its availability in public domain and it is a standard in the petroleum industry.

Results obtained were used to determine the life expectancy of the pipeline. The model is aimed to predict CO_2 corrosion rate along a carbon steel pipeline for a chosen case study. Data gathered from the case study were used to obtain results for the corrosion rate at different point along the pipeline for different pipe sizes after which sensitivity analyses of some parameters were carried out.

Petroleum Pipeline Case Study

Field data for this case study were collected within joint industry projects and the IFE [5]. These field data were chosen because actual measurement of corrosion rate was gathered from different oil companies. It is mostly used by corrosion experts in the industry to evaluate CO_2 prediction models in carrying out sensitivity analysis by running these different corrosion models for various field cases and comparing the predicted results with the actual measured corrosion rate [6]. The case study is a petroleum pipeline with 24" (the oil industry uses inches for pipe diameter) inner diameter transporting crude oil from a process facility. The pipeline is a horizontal pipe approximately 24 km in length and the topography indicates slight changes in inclination which can be negligible. For the purpose of this study, a section of 10 km was chosen to carry out the research. Twenty different subsections along the pipe were selected with an interval of 0.5km each. *Table 1*shows the summary of data collected from this case study.

***Table 1**: Secondary field data*

Inlet Temperature	44^{o} C
Inlet Pressure	24 bar
CO_2 content in gas	3 mole %
Water cut	1 %
H_2S content in	15 ppm

gas	
Pipe inner diameter	0.6096 m
Pipe thickness	0.0508 m
Pipe length	10000 m
pH	3.5 – 6.5

Mathematical Model

General equations were obtained from [7], which provide a reference for design and implementation of industrial heat transfer principles, applications and rules of thumb.

Temperature

The temperature at distance *d* along a pipeline is determined or calculated by Equation (1) below

$$T_d = T_s + (T_i - T_s)e^{-\left(U\times\pi\times ID/_{Q\times C}\right)d} \tag{1}$$

The overall heat transfer coefficient U varies upon the thermal conductivity of the material selected. The corrosion model predicts CO_2 corrosion rate of a carbon steel, therefore a thermal conductivity of the material and the heat transfer coefficient are introduced into Equation (2)

$$U = {}^{1}\Big/\left(\frac{1}{h_o} + \frac{dx_w}{k} + \frac{1}{h_a}\right) \tag{2}$$

Where $h_o$andh_a are heat transfer coefficient of oil and the surrounding atmosphere respectively.$K$is the thermal conductivity of the pipe material and d_{xw} is the pipe thickness in m.

Corrosion rate is a temperature dependent function. To calculate the CO_2 corrosion rate for carbon steel at a temperature ranging from 20 ^{o}C to 150 ^{o}C, the empirical relation built by NORSOK in Equation (3) is introduced.

$$CR_T = K_T \times f_{Co2}{}^{0.62} \times (S/19)^{0.146\,+\,0.0324\log(f_{Co2})} \times f(pH)_T \tag{3}$$

The temperature related constant $K_T$was generated by linear extrapolation from the temperature range of 5 to 150 ^{o}C

Co_2Fugacity

The fugacity f_{CO2}simply measures the molar Gibbs energy of a gas which is closely related to the thermodynamic actions along the pipeline. Fugacity is used rather than pressure due to its accuracy in chemical equilibrium calculations. To determine the fugacity of CO_2, Equation (4) gives the expression.

$$f_{CO2} = a \times p_{CO2} \tag{4}$$

The fugacity coefficient *a*is expressed as a function of temperature and is given as

$$a = 10^{\,P\times(0.0031-1.4/T_d)}\ for\ P_d \le 250\ bar \tag{5}$$

Or

$$a = 10^{\,250\times(0.0031-1.4/T_d)}\ for\ P_d > 250\ bar \tag{6}$$

The CO_2 partial pressure P_{CO2} has to be less than the total pressure of the pipeline. This translates that the percentage mole and the kmole/h of CO2 are dependent on the total pressure. It can be found by Equation (7).

$$p_{CO2} = (mole\ percent\ of\ CO_2/100\%) \times P_d \tag{7}$$

Where $P_d$is the pressure at distance *d* and is determined by introducing the Darcy-Weisbach equation for pressure losses at distance *d*

Density, Viscosity and Reynolds Number

As the fluid contains both water and oil, the viscosity and density have to be determined at the distance *d* along the pipeline.As temperature decreases, viscosity increases. To calculate the density *(ρ_w)* and viscosity *(μ_w)* of water at any temperature $T_d$the following equations are given (assuming water density at 20 °C = 998.2 Kg/m^3).

$$\mu_w(T_d) = \big((T_d + 273) - 225.4\big)^{-1.637} \tag{8}$$

$$\rho_w(T_d) = \frac{998.2}{\big(1 + 0.0002(T_d - 20)\big)} \tag{9}$$

The density of oil (ρ_o) at temperature T_d is given as

$$\rho_o(T_d) = \rho_{20} - (1.825 - 0.001315\rho_{20})(T_d - 20) \tag{10}$$

Where ρ_{20} is the density of oil at 20 °C

To get our oil viscosity *(μ_o)* the Beggs and Robinson correlation is used to predict at any temperature T_d along the pipeline and is given as

$$\mu_o(T_d) = 10^{y\left(\frac{9T_d+160}{5}\right)^{-1.165}} - 1 \tag{11}$$

$$where\ y = 10^{3.0324-0.02023G} \tag{12}$$

G is the API gravity of the crude oil.

The mixture density *(ρ_m)* and mixture viscosity *(μ_m)* at temperature T_d will be calculated with the following expression in equations below and later substituted into Equation (26) to get the Reynolds number *(Re).*

$$\frac{1}{\mu_m(T_d)} = \frac{(WC/100)}{\mu_w(T_d)} + \frac{(1 - WC/100)}{\mu_o(T_d)} \tag{13}$$

$$\rho_m(T_d) = \rho_w(T_d) \times \frac{WC}{100} + \rho_o(T_d) \times \left(1 - \frac{WC}{100}\right) \tag{14}$$

Where WC is the water content in %.

Reynolds number is given as:

$$Re(T_d) = \frac{\rho_m(T_d)V \times ID}{\mu_m(T_d)} \tag{15}$$

V isthe flow velocity of the fluid along the pipeline.

Friction Factor

Friction that occurs between the fluid and the surface wall contributes to the change in pressure along the pipeline. As a dimensionless factor, the quantities that it depends upon tend to also appear dimensionless. This factor primarily depends on the velocity, density, viscosity, pipe diameter and the roughness of the wall. The friction factor f at temperature T_d is calculated by introducing the Reynolds number into Equation (16)

$$f(T_d) = \frac{16}{Re(T_d)} \tag{16}$$

Pressure

The friction factor is introduced to the Darcy-Weisbach equation to calculate the pressure loss (ΔP_f) at distance d.

$$\Delta P_f = 4\, f(T_d) \frac{l}{D} \rho_m(T_d) \frac{V^2}{2} \tag{17}$$

To determine the pressure (P_d) at distance d, we subtract the change in pressure from the inlet pressure (P_i) which is given as;

$$P_d = P_i - \Delta P_f \tag{18}$$

Wall Shear Stress

Liquid flowing through a pipe is repelled by a viscous shear stress within the liquid and the nature of its instability around the walls of the pipe due to the surface roughness.

The steady state flow in the case of a constant diameter pipe is driven by a pressure force. The effect of viscosity provides restraining force that gives a balance for the pressure which the fluid flow with no acceleration. The wall shear stress (S) is calculated fromEquation (19)

$$S(T_d) = \frac{f(T_d)\rho_m(T_d)V^2}{8} \tag{19}$$

pH Function

From the water chemistry of pH range from 3.5 to 6.5, the pH factor is a function or factor for any given temperature *T* at a distance ***d.***

Cost Estimation

The "unit in place methodwas used in carrying out determination of the replacement cost new estimate of a pipeline. The unit in place base rates from the Saskatchewan Assessment Management Agencyshown in Table 2 gives an account for all associated direct and indirect cost of a pipeline project. The replacement cost will be valued at 75% of the new or initial cost.

***Table 2**: Rates for transmission pipelines*

Pipe Diameter	**Oil Pipeline Rate**		
	Rate		**Rated volume**
(inch)	($/mile)	($/meter)	Bbls/day
24	619,500	385	199,000
26	670,300	417	220,000
28	721,700	448	242,000
30	773,100	480	263,000
32	824,500	512	285,000
34	875,900	544	306,000

Life expectancy

The life expectancy of the pipeline was calculated by dividing the pipe acceptable thickness loss by the minimum corrosion rate for the base case (See Equation 20). The acceptable thickness loss of the pipe was chosen to be 75% of pipe thickness. This is a limit or design capacity whereas the 25% was considered to be the safe operating envelope.

$$Life\ expectancy(years) = \frac{Acceptable\ thicness\ loss\ (mm)}{Minimum\ corrosion\ rate\ (mm/year)} \quad (20)$$

The same procedure will be repeated for different pipe sizes (26, 28, 30, 32, 34 and 36 inch) with the same operating conditions. The findings will be analysed in relation and comparison of the different cases to the case study.

RESULTS AND RESULT DISCUSSION

The data sets from the case study were run with the model and results were obtained. The temperature along the pipeline decreases with distance as shown in Figure 1. This is due to increase in surface area of which the heat is lost to the surrounding. The maximum corrosion rate attained was 0.772 mm/year at a temperature of 43.7°C while the minimum corrosion rate was 0.733 at a temperature of 39.1°C.Figure 2confirms that corrosion rate is temperature dependent whereby it decreases as temperature declines along the pipeline. Assuming a uniform corrosion along the pipeline, the life expectancy is given to be 34 years. Therefore, in 34 years an amount of $7,038,150 will be spent in other to keep the petroleum pipeline in operation for the purpose of crude transportation.

The results presented above represents the aspect of corrosion rate relating to temperature and the pipe distance for the case study.

Figure 3presents the corrosion rate for all the cases from results obtained. The maximum corrosion rate of 0.772 mm/year was attained from the base case at a distance of 500 meters while the minimum corrosion rate was 0.690 mm/year for Case Six.

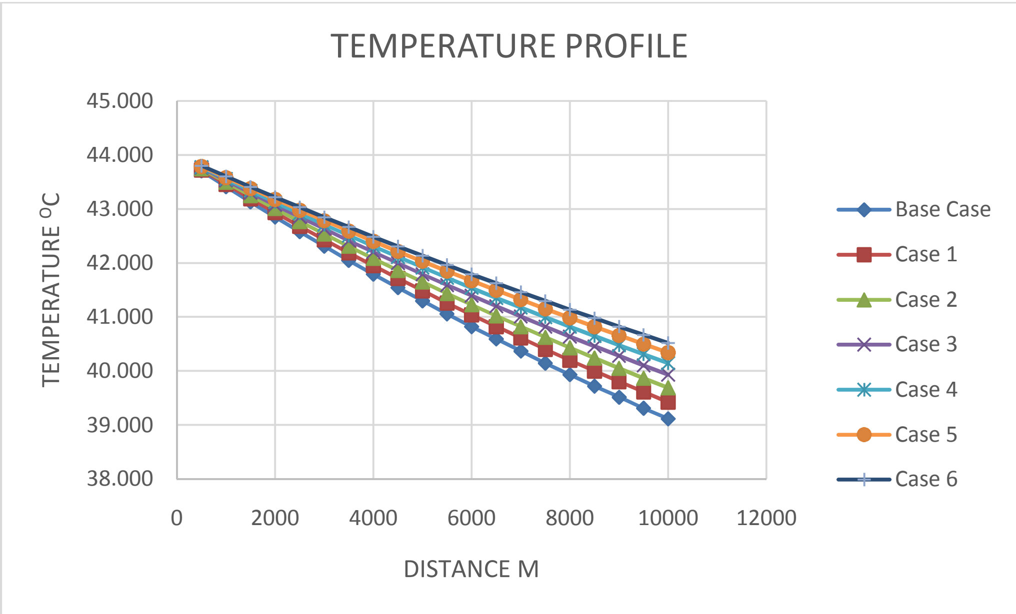

Figure 1: *Temperature profile*

The temperature profile presented in *Figure 2* shows the variation of temperature along the pipeline for different cases. All cases vary due to the pipe size. This was as a result of the heat loss to the environment. The size of the pipe determines the amount of heat loss to the surrounding which is dependent on the overall heat transfer coefficient per unit area. The larger the diameter of the pipe, the more heat will be loss to the surrounding which reduces the temperature of the fluid. As a result of this, the corrosion rate also decreases with decrease in temperature along the pipeline.

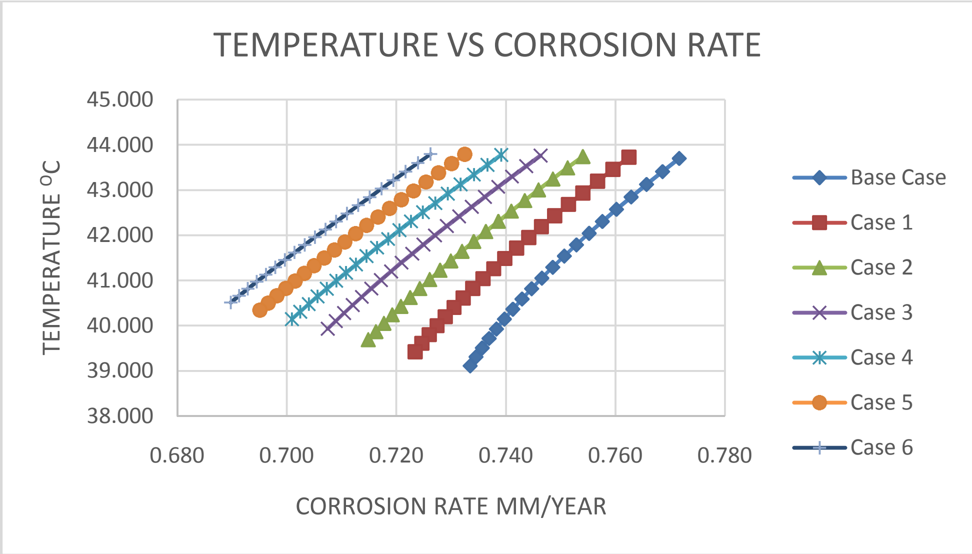

Figure 2: *Temperature vs. corrosion rate*

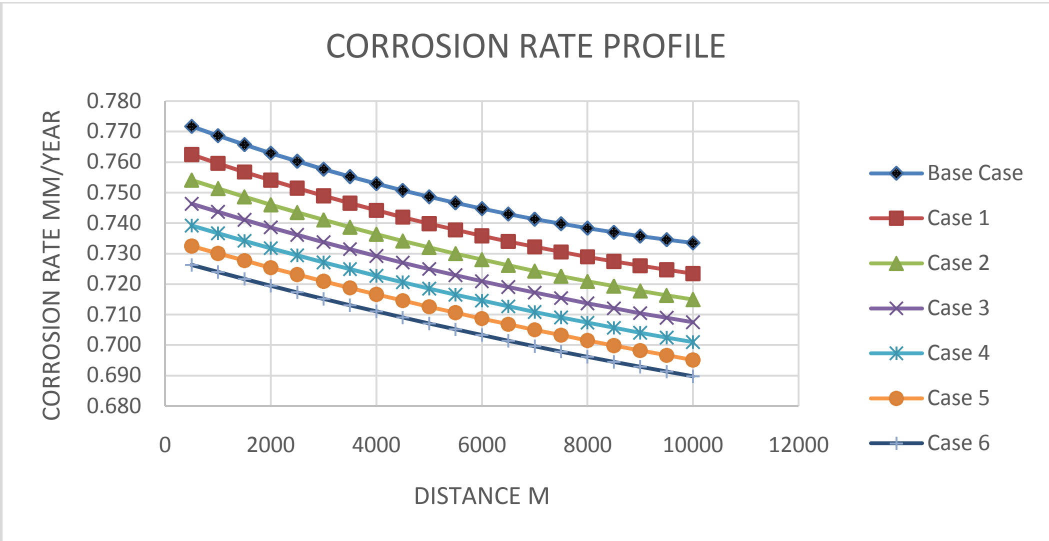

Figure 3*: Corrosion rate profile*

*Table 3*presents the maximum and minimum corrosion rate for each case. This shows that the difference in corrosion rate between each case at different distance does not decrease linearly.

Table 3*: Minimum and maximum corrosion rate*

Pipe size (inch)	**Minimum corrosion rate** (mm/year)	**Maximum corrosion rate** (mm/year)
24 (base case)	0.733	0.772
26 (case one)	0.723	0.763
28 (case two)	0.715	0.754

30 (case three)	0.707	0.746
32 (case four)	0.701	0.739
34 (case five)	0.695	0.733
36 (case six)	0.69	0.726

The cost to carry out the pipeline project was estimated using the base rate method from the Saskatchewan Assessment Management Agency. The assessed value of pipeline construction and replacement/maintenance cost for each pipe case is presented in*Table 4*.

Table 4: *Assessed value for each case*

Pipe size (in.)	**Costruction cost** ($)	**Maintenance/replacement cost** ($)	**Total Cost** ($)
24 (base case)	4,021,800	3,016,350	7,038,150
26 (case one)	4,330,200	2,165,100	6,495,300
28 (case two)	4,638,600	1,623,510	6,261,110
30 (case three)	4,947,000	1,174,913	6,121,913
32 (case four)	5,255,400	591,232	5,846,632
34 (case five)	6,450,600	241,879	6,692,497
36 (case six)	7,394,055	-	7,394,055

The estimates were carried out based on the estimated life expectancy of the pipe structure which is 34 years. For the base case, (i.e. 24" pipe) the total amount that will be spent to operate the pipe structure for the period of 34 year is $7,038,150 with no pipe to be replaced. The maximum amount is of the 38 inch pipe with a cost of $7,394,055. The findings in *Figure 4* show that the best cost effective option is the lowest point in the graph which is the 32 inch (ie case four) which has the minimum cost of $5,846,632.

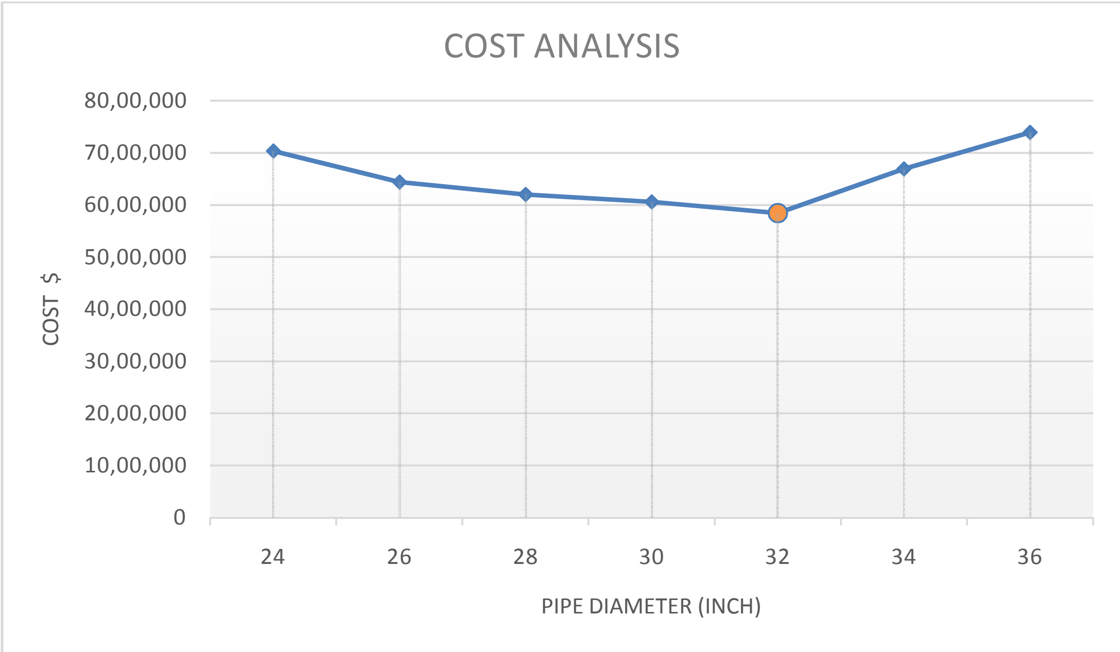

***Figure 1**: Cost analysis*

In General, larger pipe diameter presents lesser corrosion rate than the small diameter pipes for the same operating condition. However, proper analysis and size selection does not depend only on the life expectancy of the pipe but also a feasible cost which is an effective factor to be considered.

CONCLUSION AND RECOMMENDATION

In predicting the corrosion rate along a pipeline for different cases, it was discovered that temperature has a significant effect on corrosion rate regardless of various pipe sizes. It presents that the corrosion rate changes along the pipeline for different cases. From the predicted and analysed result, other sensible parameters are interrelated with temperature which is solely dependent on the heat transfer coefficient per unit area. The model developed was validated by studying the most sensible parameters of which it includes the temperature, pressure, water cut, and the fluid characteristics. Choices made in selecting a pipe size should not be decided only on the life expectancy but it should also consider the cost of the appropriate size to be selected. In conclusions, CO_2 corrosion rate of carbon steel in the petroleum industry is of importance as it impacts the economy, environment and safe operation. Cases presented in this study confirmed that material failure occurs as a result of corrosion but other causes could also lead to deterioration of material. Failure as result of internal corrosion varies and encompasses all the steps involved in a pipeline project ranging from initial design, selection of material, and construction to operation, pipeline monitoring and inspection. Defective structural design of petroleum pipeline along with the appropriate material choice is mostly prominent in numerous corrosion failures.

Based on the result obtained from this research, Cost of a pipeline project should not be limited to the financial thought but to focus on safe operating conditions, and aim to prolong the life span of the pipeline structure to the intended period from the initial design stage.

The following recommendations are suggested for future study:

- Given the limited availability of corrosion model, further investigation should be carried out using different corrosion models in other to obtain much more credible results.
- While the current study only focus on failure as a result of CO_2 corrosion, it may be advantageous to conduct research on sour corrosion which considers failure due to the presence of H_2S in oil and gas transported in pipelines. It is strongly recommended for this research study to be repeated, and this time it should consider the cost variation during the life expectancy period.

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