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LIFE PREDICTION OF CRUDE OIL PIPELINE FOR LEAKAGES MITIGATION: A CASE OF NPDC MAJOR PIPELINE OML30 – NIGERIA

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Abstract

Pipeline leak or failure is a dreaded event in the oil and gas industries. Top events such as catastrophes and multiple fatalities have occurred in the past due to pipeline leak or failure especially when loss of contents was met with fire incidents. It is therefore imperative that the causes of pipeline failure are tackled to prevent or mitigate leak incidents. This is expedient to curb the menace that goes with leak incidents, such as destruction of the environment and ecosystem; loss of assets, finance, lives and property; dangers to workers and personnel, production downtime, litigation and dent to company's reputation. This work focuses on the investigation of the actual cause of sudden pipeline failures and frequent pipeline leaks that often result to sectional pipeline replacement before the expiration of their anticipated life cycle in OML30 oil and gas field. The pipeline material selected, the standard of the minimum wall thickness of the material, the corrosive nature of the pipeline content and the observed internal corrosion rate were probed. An analysis of the rate of thinning and diminution of the internal wall of the pipeline by monitoring the interior rate of corrosion was used to forecast the remaining life of a crude oil pipeline and predict the life expectancy of a newly replaced or installed pipeline or installed pipeline.

Key Words:

Corrosion rate, Non-Destructive Test (NDT), lifetime**,** pipeline, remaining life, thickness reading, Ultrasonic Test Gauge (UTG)

1. INTRODUCTION

Pipelines are the only convenient, efficient and safe method of transferring crude oil in large quantity from the reservoir through pump stations down to the terminals. For safety reasons, pipelines are installed on a right of way specified with a location class. A pipeline Right of Way (ROW) is a narrow or thin piece of land of varying widths where the pipeline and other ancillary facilities are installed. It is a ceded strip of land over which the pipeline operator exercises authority to carry out activities in line with an agreement reached with the landowner. OML30 oil and gas

field maintains a 30metres (approximately 100feet) ROW – 15metres (or 50feets) to the right and to the left respectively. This is clearly specified with drawing/picture attached to the ROW agreement. The presence of ROW permits workers access for pipeline installations, operations, maintenance, inspections, testing or in case of emergency. Row also specifies an area where certain activities are proscribed to uphold safety and pipeline's integrity(DPR, 2007).

Pipeline location class depicts the number and nearness of buildings or dwellings for human occupancy and population density along pipeline right of way. It is a geographical area along pipeline right of way divided into classes from 1 (rural or sparsely populated) to 4 (urban or densely populated) based on proximity and number of building occupancy. In setting location class, future development that may occur along pipeline route are usually put into consideration as a location class 2 may become a location class 3 in a few years. Location class 1 is used to describe areas with sparse populations such as farmlands, wasteland, deserts and mountains. It has ten (10) or less buildings per mile for human occupancy. Location class 2 describes an area where there are more than ten (10) but less than forty-six (46) buildings per mile for human occupancy. Location class 3 depicts an area with forty-six (46) or more buildings per mile for human occupancy. Location class 4 is an advanced form of location class 3 with the existence of heavy traffic, numerous multi-storey buildings and infrastructural facilities. It should be noted that ROW and pipeline class location parameters are critically considered when calculating the wall thickness of pipelines transporting natural gas but not useful for the estimation of the wall thickness of pipelines conveying liquid such as crude oil (DPR, 2007).

Crude oil exploration from reservoirs no doubt contains solid particles comprising sand, debris and other sediments such that initiate erosive wear which if no attention is paid, could result to partial or total dilapidation of an entire production process (Berghuvud et al., 2011). Crude oil pipelines are subject to leaks or failure with time due to diverse causes. One of the main difficult tasks with the employment of crude oil pipelines is combating corrosion. Corrosion contributes approximately 25% of the total causes of failure or leakages of crude oil pipelines and over 50% of this predicament is traced to internal corrosion (Ossai, 2012).

Corrosion does not occur in pipelines that are oil wet and as such pipelines transporting crude oil with less than 0.5% Basic Sediments and Water (BS&W) are highly durable and have a history of long service life (Been et al., n.d.; CEPA, 2013). Corrosion of crude oil pipelines does not only minimize the lifespan of pipelines but also poses threat to life, assets/facilities and the immediate environment (Xu & Xiaoyu, 2014). The presence of continuous rise in BS&W changes water-in-oil to oil-in-water emulsion which enhances the speed of internal corrosion. Depletion of crude oil reserves is the reason for extracting crude oil with high BS&W resulting to high rate of interior corrosion and consequently, an increase in the frequency of pipeline leaks and failures (Ilman & Kusmono, 2014).

Crude oil from most wells in OML30 oil and gas field comes along with a high percentage of basic sediments and water of over 65%, thereby causing the crude oil content to be highly corrosive. This high BS&W is the major driving force causing corrosion or the gradual metal loss in the carbon steel pipelines carrying the crude oil. The rate of corrosion or gradual metal loss increases because of the rapid motion between this corrosive fluid and the inner wall of the pipeline. This is called erosion corrosion. A high flow rate will hasten the removal of the protective film on the metal wall surface which results in further increase of the rate of corrosion (Najlaa Hassan, 2019). The continuous production process without appropriate checks in place to reduce corrosion rates

usually results to crude oil leaks and sudden pipeline failure. This often leads to damage of the fragile ecosystem and the immediate environment; assets and facilities and lives and property. Breakdown and long downtime in crude oil production process and operations are more often due to pipeline failures. Therefore, material selection, the design and layout of crude oil pipelines should be considered and monitored in order to prevent any form of wastage in production (Olafimihan et al., 2015).

This work focuses on investigating the actual cause of sudden pipeline failures and frequent pipeline leaks that often results to sectional pipeline replacement before the expiration of their anticipated life cycle in OML30 oil and gas field in Nigeria. An investigation into the pipeline material selected, the standard of the minimum wall thickness of the material, the corrosive nature of the pipeline content and the observed corrosion rate were considered in the study.

2. MATERIAL SELECTION AND DESIGN

2.1 Material Selection Standard for Pipelines

Optimum material selection techniques are adopted in crude oil pipelines to guarantee high efficiency and reliability. This is done in such a way that while cost is being minimized, safety which is paramount is totally guaranteed and should never be undermined. The following are the key factors that are considered in pipeline material selection techniques (Olafimihan et al., 2015):

- Good market availability, documented fabrication and service performance.
- Minimal costs, interchangeability and availability of relevant spare parts.
- Design life.
- Operating conditions.
- Previous experience with materials and corrosion protection methods from conditions with similar corrosives.
- System availability requirements.
- Philosophy applied for maintenance and degree of system redundancy.
- Weight reduction.
- Inspection and corrosion monitoring possibilities.
- Effect of external and internal environment, including compatibility of different materials.
- Evaluation of failure probabilities, failure modes, criticalities and consequences: Attention is usually paid to any adverse effects that material selected may have on human health, environment, safety and assets.
- Environmental issues related to corrosion inhibition and other chemical treatments.

Carbon steels are usually the common materials often selected for crude oil pipelines as a result of their good mechanical properties, low cost and readily availability (Olafimihan et al., 2015).

2.2 Standard Design for Minimum Wall Thickness of Pipe

Minimum wall thickness of a pipe is the absolute minimal thickness of the pipe that can withstand or endure the pressure that will be exerted on its wall surface by its contents. The thinner the pipe wall, the lighter the pipe and the cheaper it is to manufacture (Wilhite, n.d.). Pipes with thinner walls allow more fluid flow for the same pipe size. The design of minimum wall thickness of a pipe is based on the pressure of the pipe's contents, the pipe material's allowable stress and the

outer diameter of the pipe. The following are the factors that affect pipe wall thickness requirement:-

- Maximum working pressure
- Maximum working temperature
- Chemical properties of the fluid contained in the pipe
- The velocity of the fluid
- The material and grade of the pipe
- The safety factor or code design application

The following are the major two methods for determining the minimum wall thickness of a pipe conveying liquid such as crude oil.

2.2.1 Use of Procedure

Applying this method during design, the following three key parameters are considered in determining the minimum wall thickness of the pipe; which are; the maximum (operating) pressure that the pipe is expected to experience, the allowable stress of the material to be used and the outer diameter of the pipe. The following procedure is therefore employed to obtain the minimum thickness of the pipe (Wilhite, n.d.):

Step 1

Determination of the maximum pressure that the pipe will endure: This is the maximum pressure the fluid contained in the pipe must not exceed. It is obtained from documented design parameters of the piping or vessel usually given in pounds per square inch (psi).

Step 2

Determination of the allowable stress of the wall material: The allowable stress can be the tensile or yield stress of the material. The value of the allowable stress for a material can be obtained from the American Society of Mechanical Engineers' standard B31.3 (ASME, 2021). The carbon steel pipe material being used in OML30 is ASTM A106 grade B and the recommended allowable stress value at 100 degree Fahrenheit given by ASME B31.3 for such carbon steel pipe material is 19.9KSI (or 19,900psi).

Step 3

Selection of an outside diameter in inches for the pipe: This is the diameter of the pipeline selected based on the quantity of fluid it is expected to convey. It is usually decided by the company as advised by the pipeline engineer.

Step 4

Multiplication of the outside diameter in inches by the pressure in psi by 1/2;

Step 5

Division of the result of Step 4 by the allowable stress: The result obtained is the minimum wall thickness assuming an ideal condition.

Step 6

Multiplication of the minimum wall thickness assuming ideal conditions by a safety factor or by the manufacturer's mill tolerance: The manufacturer's mill tolerance is often given as 12.5 percent or 15.0 percent as a result of variations in the pipe's strength. A 15 percent tolerance converts to 115 percent of the minimum wall thickness, or a multiplier of 1.15.

2.2.2 Use of Formula

The use of formula is considered in determining the minimum wall thickness of a pipe. The formulae for calculating the minimum wall thickness of a pipe is given (Khanin, n.d.; Olafimihan et al., 2015) as:

$t_m = t_c + 12.5\%$ of the calculated pipe wall thickness (1)

$t_c = \frac{PD}{2(SE+PY)} + C$ (2)

Where;

t_m = Required minimum wall thickness of pipe

t_c = Calculated wall thickness with addition of corrosion allowance

P= Internal design gauge pressure

D= Outer diameter of the pipe

S= Allowable Stress value of the Pipe Material due to internal pressure given as 19,900Psi (ASME, 2021)

E= Quality factor, and for seamless carbon steel material, it is given as 1 (ASME, 2021)

Y= Value of coefficient; it is a standard code for which for carbon steel it is given as 0.4. (ASME, 2021). The value of coefficient Y for thickness t < D/6 at a given temperature is given for all pipe materials by ASME B31.3. as shown in the table below. Y is 0.4 for all carbon steel materials at all temperatures.

Table 1: Values of Coefficient Y for t < D/6 (ASME, 2021; Khanin, n.d.)

	Temperature, °C (°F)							
Material	482 (900) And Below	510 (950	538 (1,000)	566 (1,050)	593 (1,100)	621 (1,150)	649 (1,200)	677(1,250) and Above
Ferritic Steel	0.4	0.5	0.7	0.7	0.7	0.7	0.7	0.7
Austenitic Steels	0.4	0.4	0.4	0.4	0.5	0.7	0.7	0.7
Nickel Alloys UNS Nos. N06617, N08810 And N08825	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.7
Gray iron	0.0	….	…..					
Other Ductile metals	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

C= Mechanical, erosion and corrosion allowances and the common value for carbon steel is 3mm. it is the corrosion allowance for pipe materials that are given based on service fluid. Typical values are 3mm for carbon steel and zero mm for stainless steel. However, piping with high corrosion rates may be assigned given higher corrosion allowance (up to 6mm) as may be advised by the corrosion expert or engineer.

2.2.3. Significance of the Extra Thickness

Pipelines are designed with a minimum wall thickness to have a service life of twenty (20) years. However, during construction and installations, changes in direction may occur which will result to cold bending of pipe to form bends and elbows. These changes will result to significant wall thinning and possible position where failure may likely occur. Therefore, for the wall thickness of the pipeline not to be less than the designed or required minimum wall thickness at the bends or elbow, the extra wall thickness becomes very essential. The following are some of the importance or significance of the extra wall thickness of pipeline (Khanin, n.d.):

- To determine the life of a pipe after 20 years.
- To determine the maximum pressure holding capacity of the pipe.
- To check the extra thickness is enough to cater for thinning, if same pipe is used for producing the bend.
- The extra thickness also minimizes deflection and reduces the number of support.
- To compare pipe thickness with flange pressure holding capacity and affirm pipe is stronger than the flange.

2.2.4 Assumptions for Pipe Thickness Calculation

For the above-mentioned pipe thickness calculation steps following ASME B31.3, The following assumptions are made for the calculation of the minimum wall thickness of pipes.

- It is a thin cylinder pipe, therefore the value of thickness is less than one-sixth of the outer diameter ($t < D/6$).
- The value of $P/(SE) < 0.385$
- The pipe is subjected to internal pressure only.

2.3 Determination of Corrosion Rates

Corrosion Rates (CRs) can be determined on basis of empirical equations or on experience or measured data (Bai & Bai, 2014). A combination of the aforementioned and good engineering analysis from corrosion engineers and experts are vital. Corrosion rate can be determined from actual pipe samples obtained from a pipe and estimating metal loss over time. However, due to localized nature of different forms of corrosion, this sample corrosion rate will not be certain for a range of pipeline length. Corrosion rate can also be estimated with coupons (metal samples) or electronic devices place on or near the wall of the pipe (Muhlbauer, 2004). From these estimations, the actual rate of corrosion of a pipeline can be determined at least for a section close to the measuring device. Theoretically by the use of some empirical formulae, the rate of corrosion can also be estimated. According to Agyenim-Boateng et al. (2014), corrosion rate for gradual metal loss from the wall thickness of metal is computed by finding the difference between two thickness readings and dividing the result by the time interval between the readings. They further stressed that estimation of corrosion rate may consist of thickness readings taken at more than two separate occasions. Short-term and long-term corrosion rates are estimated and their comparison helps to identify recent corrosion mechanisms from those acting in the past. Short-term corrosion rates are computed from two consecutive most recent thickness readings while long-term rates employ most recent reading and one taken in the past during the life of the equipment (Agyenim-Boateng et al., 2014).

$$Corrosion\ rate\ (ST) = \frac{t_{previous} - t_{actual}}{time\ interval\ between\ t_{previous}\ and\ t_{actual}} \quad (3)$$

$$Corrosion\ rate\ (LT) = \frac{t_{initial} - t_{actual}}{time\ interval\ between\ t_{initial}\ and\ t_{actual}} \quad (4)$$

Where;

$t_{previous}$ is the previous thickness reading of the equipment before the most recent thickness reading

t_{actual} is the most recent thickness reading of the equipment

$t_{initial}$ is the initial thickness reading taken some time past in the history of the service life of the equipment. It might be the first thickness at time of installation or the thickness at when corrosion was first noticed or observed. Note that all thickness readings are taken at the same point of inspection. There is a range of corrosion rate that is acceptable for pipeline corrosion in order not to undermine safety of the environment, lives and property as shown in table 2.

Table 2: Acceptable Corrosion rate (Ukoba et al., 2013)

Status	**ipy**	**mm/y**
Completely satisfactory	< 0.01	0.25
Use with caution	< 0.03	0.75
Use only for short exposure	< 0.06	1.50
Completely unsatisfactory	> 0.06	1.50

The acceptable corrosion rate presented in table 2 is compared with the corrosion rate presented by (Baby et al., 2016) for two different types of crude oil as shown in table 3:

Table 3: Review of Corrosion rate C_r(mm), Actual thickness T_a(mm) and Retiring thickness T_r(mm) (Baby et al., 2016)

For Kuwait Crude oil (Sour Crude)				**For Arab Extra Light (Sweet Crude)**			
Line	C_r (mm/y)	T_{actua} (mm)	$T_{require}$ (mm)	Line	C_r (mm/y)	T_{actual} (mm)	$T_{require}$ (mm)
Preheated crude inlet Piping	0.7082	12	3.487	Preheated crude inlet Piping	0.608	12	3.487

2.4 Estimation of Remaining Life

Corrosion rates are usually expressed in mils per year and are used to estimate the lifespan of pressure vessels or chemical equipment. According to Kutz (2018), the service lifetime of a chemical equipment or pressure vessel can be calculated by finding the ratio of the (minimum) wall thickness of the equipment to the corrosion rate thus:

$$Estimated\ service\ lifetime = \frac{(minimum)\ equipment\ wall\ thickness}{corrosion\ rate} \quad (5)$$

It should be noted that the service lifetime for general corrosion is usually longer than the service lifetime for localized corrosion rates. The formula is acting as a guide to forecast the possible time the vessel or pipeline will fail. It is therefore up to the management to decide on when to replace such a vessel or pipeline before it will fail. As failure should not be an option to any institution, the formula therefore indicates when the pipeline will possibly fail so as to plan or take the right decision. The remaining life of a pipeline (in years) can be estimated from the relation:

$$Remaining\ Life\ (RL) = \frac{t_{actual} - t_{critical}}{corrosion\ rate} \quad (6)$$

Where;

t_{actual} is the most recent thickness reading of the equipment

$t_{critical}$ is the observed thickness of pipeline at failure from record history i.e. the thickness below which the pipeline will fail as observed from history of operations.

3. METHOD OF STUDY

Pipeline statistics and historical data peculiar to certain pipelines in particular region or environment will enable experts to accurately predict the lifespan of a crude oil pipeline or the remaining life of the pipe. In this work, an investigation into the lifespan and life expectancy of crude oil pipeline was conducted. This is done to predict the life expectancy of a newly installed or replaced pipeline and/or to predict the remaining lifetime of an already existing crude oil pipeline. The investigation was carried out using an NPDC major pipeline in OML30 oil and gas field as case study. This research involved a full understanding of the concept of pipeline failure so as to prevent or mitigate pipeline leakages. The methods used in this study involve the following;

a. Data collection of pipeline parameters from the manufacturer manual and the field of operation.
b. Computing the minimum wall thickness of a straight seamless carbon steel pipe using two different methods.
c. Comparing the required standard minimum wall thickness of the pipe computed with the wall thickness of the pipeline in use to establish whether the pipe is standard or substandard.
d. Analyzing data obtained from non-destructive test (NDT) carried out over a period (of ten years) using ultrasonic thickness gauge (UTG).
e. Obtain the rate of corrosion of the specific pipeline per year and use the corrosion rate to predict the lifespan and the remaining life of pipelines that are in use in that region.

3.1 Method of Data Collection

The parameters needed for this work are the design pressure, design temperature, outer diameter (OD), pipe wall thickness, safety factor, thickness readings and the time interval of the readings. These parameters were obtained from pipeline (carbon steel material) configuration in the manufacturer's manual and the non-destructive test data (obtained using the Ultrasonic Thickness Gauge (UTG) equipment) at the NPDC library in OML30 oil and gas field. The UTG equipment is calibrated regularly before employing it to collect data in the field. During data collection, points were randomly selected on the pipeline and spots with the greatest metal loss are noted as critical spots which are used as yardsticks for judgments. The frequency of reading is once per month and an average is taken yearly.

Table 3. Pipe Parameters of a Carbon Steel Material

Description	Value	Unit
Design Pressure	30 (435.113)	Bar (Psi)
Design Temperature	100	°F
Outer Diameter (OD) of pipe	28 (711.200)	In (mm)
Wall thickness of pipe	0.625 (15.875)	In (mm)
Manufacturer's mill tolerance (safety factor)	12.5%	-

Source: NPDC Library in OML 30 Oil and Gas Field.

With the data collected as shown in table 3 and 4, an analysis is carried out to complete this investigation with graphical plots using excel software to obtain results which are judged to draw conclusions and recommendations.

Table 4. Non-Destructive Test (NDT) Data of a Crude Oil Transmission Pipeline

YEAR	THICKNESS READING (MM)	AVERAGE METAL LOSS (MM)	CUMULATIVE AVERAGE METAL LOSS (MM)
2009	15.5090		
2010	15.0098	0.4992	0.4992
2011	14.5088	0.5010	1.0002
2012	14.0055	0.5033	1.5035
2013	13.5004	0.5051	2.0086
2014	12.9930	0.5074	2.5160
2015	12.4840	0.5090	3.0250
2016	11.9728	0.5112	3.5362
2017	11.4594	0.5134	4.0496
2018	10.9443	0.5151	4.5647
2019	10.4270	0.5173	5.0820

Source: Non-Destructive Test (NDT) Data at *NPDC Library in OML 30 Oil and Gas Field.*

4. DATA ANALYSIS AND RESULT DISCUSSION

4.1 Minimum Wall Thickness Computation.

4.1.1 Method 1- Use of Procedure:

Step 1: Ascertaining the maximum operating pressure of the fluid content that the pipe will endure. This is obtained from the design parameters of the pipe which is given as 30Bar (or 435.113Psi) as seen in table 3.
Step 2: Obtaining the allowable stress of the pipe material. The carbon steel pipe material being used in OML30 is ASTM A106 grade B and the recommended allowable stress value at 100 degree Fahrenheit given by ASME B31.3 for such carbon steel pipe material is 19.9KSI (or 19,900psi).
Step 3: Selecting the Outer Diameter of the Pipe. This is obtained from the design parameters of the pipe which is given as 28In (or 711.200mm) as seen in table 3.
Step 4: Obtain half of the product of the Outer diameter and the design pressure as follows: 28 inches x 435.113psi x 1/2 = 6091.582

Step 5: Assuming Ideal Condition. The result in step 4 is divided by the allowable stress to obtain the minimum wall thickness. That is 6091.582 divided by 19,900 to obtain a minimum allowed thickness of 0.3061inches.
Step 6: Considering the safety Factor. The manufacturer's mill tolerance given as 12.5% in table 2 converts to 112.5% of the minimum wall thickness or multiplier of 1.125. Therefore 0.3061 x 1.125 = 0.344363inches gives an approximate value of **0.344inch** or minimum pipe wall thickness. Extra thickness available = 0.625 – 0.344 = 0.281inches or 7.137mm

4.1.2 Method 2 – Use of Formula:

$t_c = \frac{435.113 \times 711.2}{2(19{,}900 \times 1 + 435.113 \times 0.4)} + 3 = 10.708mm$ (From Eq. 2)
$t_m = t_c$ + 12.50 % of the pipe thickness (From Eq. 1)
$t_m = t_c/0.875 = 10.708/0.875 = 12.238mm$
Extra thickness available = 15.875 – 12.238 = 3.637mm

4.1.3 Comparison of the wall thickness of the Pipeline in Use with the required Standard thickness of Pipeline

The two methods revealed that there is availability of extra wall thickness which implies that the pipeline in use is standard. Ideally, the life cycle of the pipeline under investigation should have increased with the extra thickness available, but this is not so in reality.

4.2 Analyzing Data obtained from Non-Destructive Test Carried out on the Pipeline in Use.

Table 3 shows the data obtained from the non-destructive test carried out on a pipeline for a period of ten years using ultrasonic thickness gauge. The data presents the yearly average metal loss for the specific pipeline under investigation. From the data, it can be deduced that the metal loss experienced from the average metal loss for the period under review is over 5mm. Diminution and thinning of pipeline wall thickness due to gradual loss of metal from the interior wall of the pipeline were monitored monthly with yearly average taken for a duration of ten (10) years to establish the rate of corrosion (both short-term and long-term) to predict the remaining life of the pipeline to mitigate leakage and by extension to possibly estimate the entire service life of newly installed or replaced pipelines. Judgment of prediction and outright rejection should be based on these parameters to determine the usage worthiness of pipelines in this region.

4.2.1 Short-term Corrosion rate (ST)

$Corrosion\ rate\ (ST) = \frac{10.9443mm - 10.4270mm}{2019yr - 2018yr} = 0.5173mm/yr$ (Ref: table 4 and eq. 3)

4.2.2 Long-term Corrosion rate (LT)

$Corrosion\ rate\ (LT) = \frac{15.5090 - 10.4270}{2019yr - 2009yr} = 0.5082mm/yr$ (Ref: table 4 and eq. 4)

These corrosion rates (ST and LT) are high and therefore the pipeline must be used with caution strictly in order to mitigate leakages. The life expectancy and remaining life of a pipeline can be calculated if we know the minimum thickness at which failure will occur under normal operations. According to Olafimihan et al (2015), the thickness of a pipeline carrying crude oil should not be allowed to be less than 0.25 inch (6.35mm) otherwise pipeline failure will occur. Although the design pressure is 30bar, during normal operations, the pressure of the crude oil content in the

pipeline as records has it is normally less than 10bar. Pipeline statistics and historical data in the field shows that failure of pipelines normal occur at less than 0.15inch (< 3.81mm) wall thickness of the pipeline and no pipeline has failed at 0.15inch (< 3.81mm). **3.81mm** was therefore set as the critical wall thickness at which crude oil pipeline in this region will fail; the value was also used as the basis for the research prediction.

4.2.3 Estimated Service lifetime of Pipeline

$Estimated\ service\ lifetime = \frac{15.875mm - 3.810mm}{0.5173mm/yr} = 23.3\text{yrs}$ (Ref: table 4 and eq. 5)

4.2.4 Remaining Life of Pipeline

$Remaining\ Life\ (RL) = \frac{10.4270mm - 3.810mm}{0.5173mm/yr} = 12.8yrs$ (Ref: table 4 and eq. 6)

As seen from the above computations, pipelines in the region under review with same configuration will only last for 23.3years. For the pipeline under review, the remaining life is 12.8years from 2019. We estimated the lifespan of pipeline and the remaining life of the pipeline under review from the excel plot. The excel plot in the following figures gave a model which predict the life expectancy of pipeline and forecasted the remaining life of the pipeline under investigation.

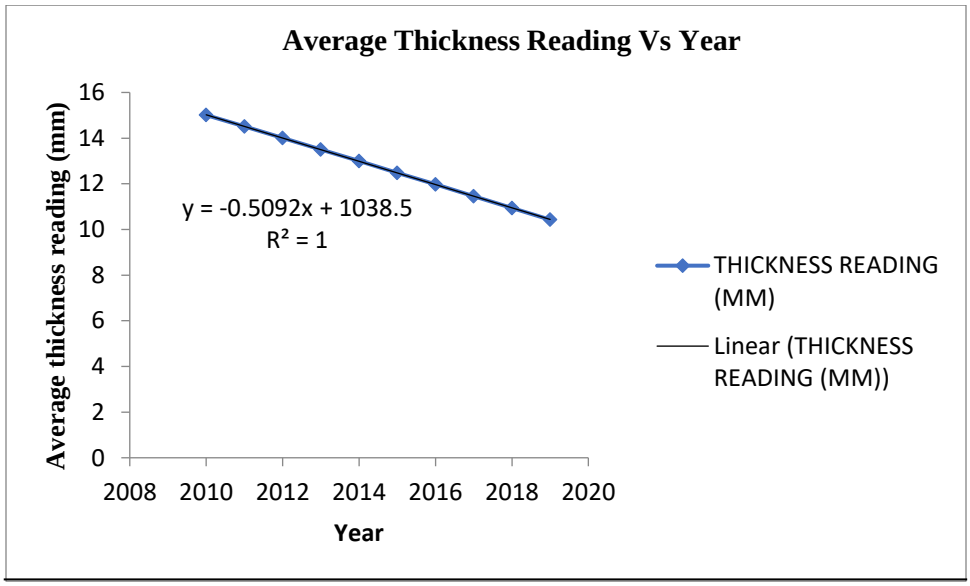

Figure 1. Plot of average Pipe Wall Thickness Vs. Year

The excel software model for previous and subsequent thickness reading is given as $y = -0.5092x + 1038.5$, where y = the average thickness reading (in mm), x = year under review, -0.5092 is the gradient of wall diminution and 1038.5 is a constant. 13years from 2019; x will be 2032 and the thickness of the metal:

$y = -0.5092 \times 2032 + 1038.5 = 3.8056mm$, and this value is less than 3.81mm (< 0.15inch). Therefore, in order to prevent or mitigate leakage, the pipeline should not be employed beyond the next 12.5years which corroborates the value of 12.8yrs that was earlier obtained through calculations.

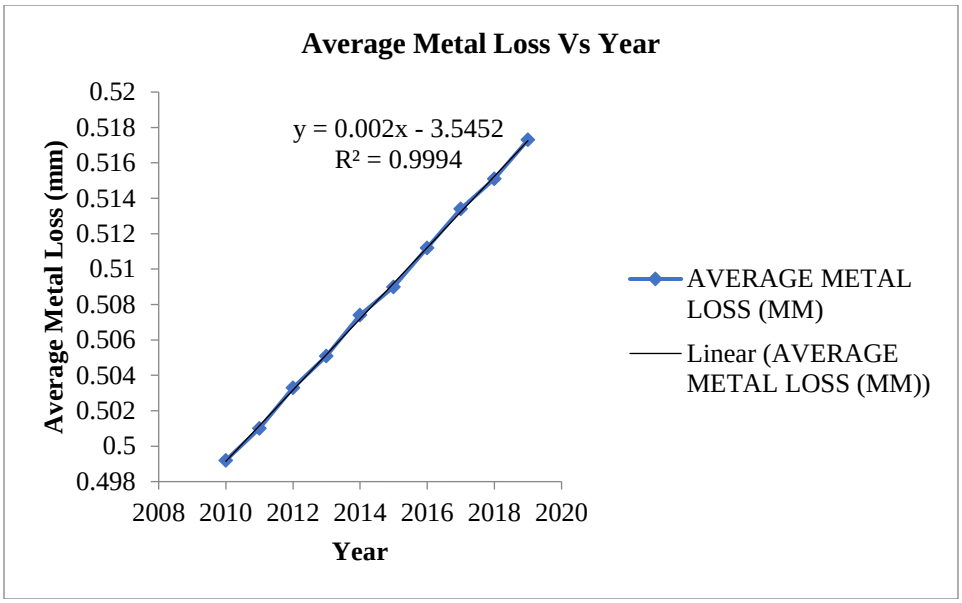

Figure 2. Plot of average Metal loss Vs. Year

As observed from the data in table 4 and figure 2, the metal loss is not constant; it varies directly with the year such that as the year of operations increases the rate of metal loss increases. Excel software has given an equation in figure 2 to predict the metal loss in any given year as $y = 0.002x - 3.5452$; where y = the average metal loss (in mm), x = year under review, 0.002 is the gradient of wall thinning and -3.5452 is a constant. The model has predicted that by 2032 the metal loss will be 0.5188. When we multiplied 0.5188 by 13years we got a total cumulative metal loss from 2019 till 2032 as 6.7444mm. The difference between the thickness reading of 2019 (10.4270mm) and the metal loss as at 2032 indicates that the thickness reading of the pipeline will be 3.6826mm which is again less than 3.81mm critical value. This is another prove that the pipeline should not be used beyond 12.5 years from 2019.

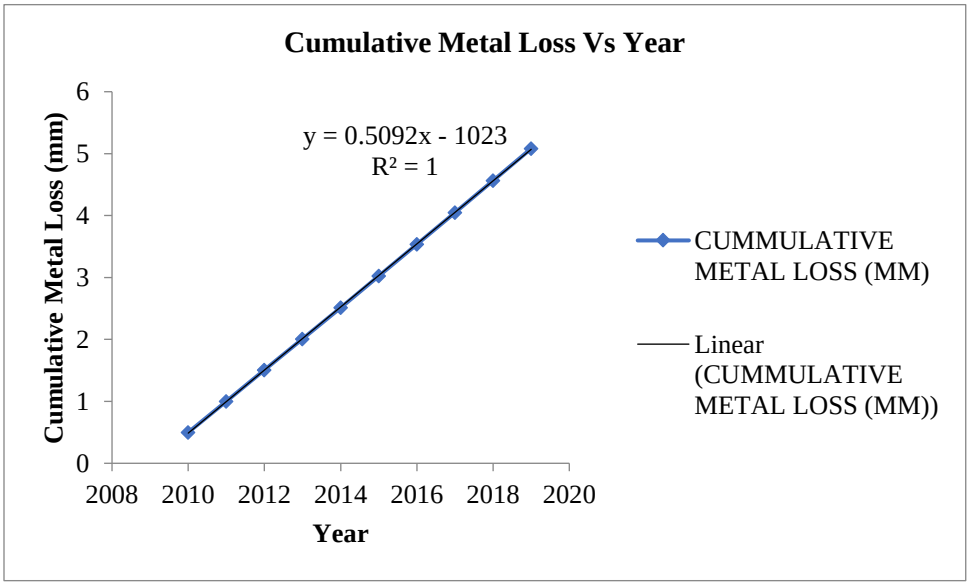

Figure 3.3: Plot of Cumulative Metal Loss Vs. Year

The model presented for cumulative metal loss by the excel software is y = 0.5092x – 1023; where y = the cumulative metal loss (in mm), x = year under review, 0.5092 is the gradient of cumulative metal loss and -1023 is a constant. By 2032, the cumulative metal loss as predicted by model would y = 0.5092(2032) – 1023 = 11.6944mm. Recall that as at 2019, the cumulative metal loss is 5.0820mm (ref: table 4) and the cumulative metal loss we got from 2019 to 2032 as predicted by the model in figure 2 is 6.7444mm. Addition of the aforementioned cumulative losses gives 11.8264mm. This value represents the cumulative value from 2009 to 2032 which should give a residual thickness reading of 3.6826mm. This value is less than 3.81mm which is also evident that the pipeline should not go beyond 12.5years from 2019 before replacement to prevent or mitigate crude oil pipeline leak.

5. CONCLUSION AND RECOMMENDATIONS

This work investigated the life expectancy and the remaining life of crude oil pipeline to prevent or mitigate leak. This was possible because the pipeline parameters and configuration and the field and manufacturer's data peculiar to the pipeline are known. The field data might change if the pipeline was to be used in a different environment in which the corrosion may be lower or even higher depending on the nature of the crude oil it is conveying whether is more or less corrosive than that of this present environment we have studied. The rate of corrosion of the pipeline in this region is really on the high side. This is as a result of the corrosive nature of the crude oil that the pipeline is conveying. The crude oil constitutes a large proportion of basic sediments and water (BS&W) of over 65% with high concentration of chlorine, hydrogen sulfide and carbon dioxide which enhances the rate of corrosion causing a high rate of thinning and diminution of the wall thickness of the pipeline. For a new pipeline or a pipeline whose service conditions are known, the life expectancy and remaining lifetime estimation procedure presented in this work can be used to determine possible corrosion rate and predict the lifespan or the remaining life of the pipeline. This is possible since the pipeline will be subjected to the same condition of service as of previous pipeline that was replaced or changed out. The portions mostly affected by corrosion were used as benchmark and yardsticks because such spots are noted as critical spots where failure or leakages will likely occur.

Based on this work, the recommendations made are as follows:

- The minimum wall thickness reached before pipeline will fail defers from one operation process to another and from one environment to another. It is therefore important to establish the statistics or historical data of the pipeline in the region concerned.
- The proposed methodology is reliable if the corrosion rate of the pipe material based on the service fluid is known and handy. The lifetime of the pipeline can therefore be reliably determined.
- Internal corrosion can be reduced or prevented by dehydration of gases and periodic pigging of lines to remove accumulated gases and debris.
- The investigation only concentrated on the internal corrosion of the crude oil pipeline as it is expected that measures are in place to check external corrosion by coating or use of cathodic protection among others.
- The use of corrosion inhibitors to reduce the rate of internal corrosion is highly recommended.

CONFLICT OF INTEREST

On behalf of all the co-authors, the corresponding author states that there is no conflict of interest.

ETHICAL STATEMENT

The authors declare that the work described has not involved experimentation on humans or animals.

AVAILABILITY OF DATA AND MATERIALS

Not applicable

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AUTHORS' CONTRIBUTION

The corresponding author contributed 55% to the work. The first co-author made an input of 25% while the second co-author impacted 20% effort on the work. All authors made inputs to all the major sections of the work.

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