

# An Investigation of Internal Corrosion of Oil and Gas Transporting Carbon Steel Pipes in the Niger Delta Area of Nigeria

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**Abstract**—Internal corrosion of carbon steel pipes of oil and gas Companies in the Niger Delta area of Nigeria using coupons and ER probes is presented. Corrosion mechanisms for the lines vary with the fluid type and operational parameters. Aqueous corrosion with, in some cases CO<sub>2</sub> corrosion additive, erosion corrosion and elevated temperature oxidation are corrosion mechanisms implicated in the pipes. No H<sub>2</sub>S-induced corrosion was observed for all the lines investigated. They act separately or synergistically to exacerbate the corrosion attack. Application of inhibitors of the amine group drastically lowered the corrosion rates. Effective inhibition regime had in an instance markedly lowered the corrosion rate of a line from 42.7080mpy to 1.3447mpy. The ER probes incorporation offered a comparative corrosion monitoring alternative and provided insight into the real time conditions of the lines over prolonged periods of times. The exercise proved very useful in determining the corrosion status of the pipes and helped to determine the lines that should require immediate maintenance intervention to obviate possible ugly incidents of breakouts and ruptures.

**Index Terms**—Carbon Steel Pipes; Corrosion Rates; Coupons; ER Probes; Internal Corrosion Monitoring.

## I. INTRODUCTION

Carbon steel pipes are used extensively by the oil and gas industries to transport large quantities of extracted oil, natural gas and petroleum products over long distances. These pipelines are crucial in providing needed fuels for the sustenance of vital functions like power generation, heating supply and transportation. Failure of these pipelines to sustain these functions through ruptures or leaks portend environmental damage, fatalities and huge maintenance and compensation costs that aggregate to huge financial losses. Indeed, numerous corrosion-related pipeline failures have occurred in Nigeria. Out of a total of 2.4 million barrel of petroleum spilled in a total of 4,835 incidents, 1.89 million barrels were spilled into the Niger Delta area between 1976 and 1996 [1]. The Nigerian National Petroleum Corporation (NNPC), estimated that 2,300 cubic metres of from an average of 300 individual spills petroleum are discharged annually into the environment [2]. Examples of spillages include the blowout of a Texaco offshore station which in

1980 dumped an estimated 400,000 barrels (64,000 m<sup>3</sup>) of crude oil into the Gulf of Guinea and Royal Dutch Shell's Forcados Terminal tank failure which produced a spillage estimated at 580,000 barrels (92,000 m<sup>3</sup>) [3]. It is pertinent to note that the oil and gas industry constitutes the major revenue generating source for Nigeria. Averting such scenarios is therefore extremely important.

Sources of failures have been linked by [4] as follows to: structural problem 40%, forced or third party damage 27%, operator error 6%, control problems 2% and others 25%. Reference [5] identified that leaks caused by corrosion constituted 86.8% of failures while ruptures constituted 13.2% of pipeline failure. The inference is that corrosion is the main cause of leaks. Reference [6] showed that for crude oil pipelines, the causes of failures appeared to be fairly random in nature and that no trends were apparent. They stated that for sour gas pipelines internal corrosion is the main source of failure and that for these about 86% of the failures were due to leaks while 14% were due to ruptures.

Reference [7] stated that there are approximately 84,000 kilometers of pipeline in Nigeria as at 1998 and that the Niger Delta region of Nigeria takes a huge chunk of this with about 64,00 kilometers. Furthermore, they stated that the Niger Delta region has about 606 oilfields with 355 situated onshore and 251 offshore with about 5,284 oil wells drilled and 527 flow stations for crude oil processing, seven sea ports and these are serviced by networks of pipelines.

The study investigates the causes of internal corrosion of carbon steel pipes that are predominantly used to transport oil and gas in the Niger Delta region of Nigeria with the aim of identifying the onset of their incidence with the consequent institution of appropriate contingency preventive measures to forestall leaks and ruptures. The objectives of the study are:

- Investigation of internal corrosion of oil and gas transporting carbon steel pipes in the Niger Delta area of Nigeria.
- Execution of corrosion analyses of coupons inserted in the pipelines for periods ranging from about 2 to 4 months using the weight loss and Electrical Resistance Probes methods.
- Determination of the prevalent internal corrosion modes in oil and gas transporting pipelines in the Niger Delta region of Nigeria.
- Determination of the pipelines that should receive immediate remedial actions via institution of inhibition regimes.

Carbon steel is steel in which the main interstitial alloying constituent is carbon in the range of 0.12–2.0% [8]. Several

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Published on August 30, 2017.

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other elements are allowed in carbon steel, with low maximum percentages. These elements are: Mn, 1.5-1.65% max., Si, 0.5- 0.60% max., and Cu, 0.60% max. Other elements may be present in quantities too small to affect its properties. Low and medium carbon non alloy steels are commonly used in the manufacture of steel pipes [8]-[10], Fig. 1.

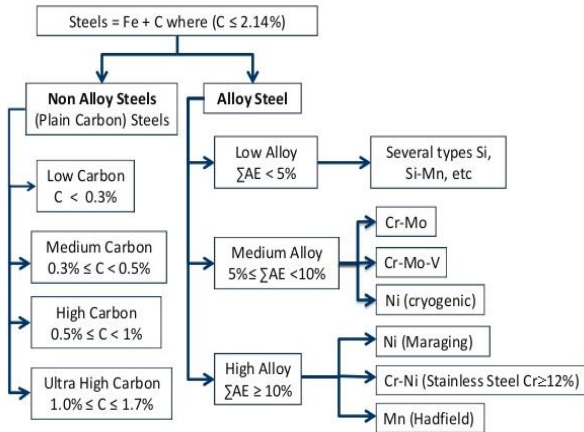


Fig.1. Composition of steel [11].

TABLE I: CHEMICAL REQUIREMENTS CARBON ALLOY STEELS USED IN PIPING APPLICATIONS AND SPECIFICATION FOR SEAMLESS AND WELDED BLACK AND HOT-DIPPED GALVANIZED STEEL PIPE [12]

Type		Element (Max Composition %)			
		C	Mn	P	S
Type S (Seamless Pipe)	Gr. A	0,25	0,95	0,05	0,045
	Gr. B	0,3	1,2	0,05	0,045
Type E (Electric-Resistance-Welded)	Gr. A	0,25	0,95	0,05	0,045
	Gr. B	0,3	1,2	0,05	0,045
Type F (Furnace-Welded)	Gr. A	0,25	0,95	0,05	0,045

- Low Carbon Steel – Composition of 0.05%-0.25% carbon and up to 0.4% manganese. Also known as mild steel, it is a low-cost material that is easy to shape. Carburizing can increase its surface hardness.
- Medium Carbon Steel – Composition of 0.29%-0.54% carbon, with 0.60%-1.65% manganese. Medium carbon steel is ductile and strong, with long-wearing properties.
- High Carbon Steel – Composition of 0.55%-0.95% carbon, with 0.30%-0.90% manganese. It is very strong and holds shape memory well, making it ideal for springs and wire.
- Very High Carbon Steel - Composition of 0.96%-2.1% carbon. Its high carbon content makes it an extremely strong material. Due to its brittleness, this grade requires special handling [13].

Weight loss technique using coupons with an electrical resistance corrosion monitoring technique as a backup were employed. Direct corrosion monitoring and assessment techniques are perhaps second to none. This is so because corrosion prediction approaches are known to suffer from either over or under corrosion rate predictions limitations because the numerous and variable corrosion parameter differences presented by environments are not fully factored into their algorithms. Indeed, in many cases the complexity and undetermined relative intensities of the corrosion types make such prediction approaches highly inaccurate.

Reference [14] for instance concluded in his study of corrosion of underground steel pipes that the models developed will always have relatively large uncertainties that will limit their utility. These uncertainties resulted from the scatter in the measurements due to annual, seasonal, and sample position dependent variations at the burial sites.

It is therefore clear that direct corrosion evaluation of installations will provide the most accurate and authentic information of the progressive integrity and time value of any asset. In this paper the corrosion of carbon steel in contact with flowing crude oil and gas in the Niger Delta area of Nigeria was investigated using corrosion coupons and electrical resistance probes.

## II. MATERIALS AND METHODS

Medium steel coupons strips of SAE, AISI 1018 (0.15 – 0.29C, 0.60 – 0.90Mn, 0.040P max, 0.050S max) grade (approximating the composition of the carbon steel pipes) are immersed in pipes in which crude oil, natural gas, glycol and recirculation water were transported.

The Corrosion Monitoring Points (CMPs) were preferentially installed on the horizontal sections and in the areas of depressions where “dead leg” corrosion is most likely to take place (Fig.1). Few CMPs are located on vertical segments of the lines (Fig. 2), elbows and bends, etc., that are usually prone to erosion corrosion were more regularly monitored for thickness variations using NDT techniques.



Fig. 1. Horizontal pipe



Fig.2. Segment with a bulge where “dead leg” corrosion could be encouraged

Fig. 3 presents a typical corrosion coupon specimen that was used in the monitoring.

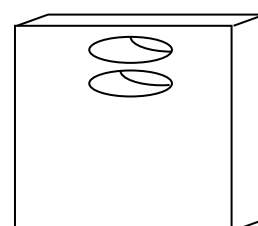


Fig. 3. Typical corrosion coupon of 73mm x 22mm x 3mm

The coupons were retrieved for analyses at intervals of between two to four months. Visual observations were recorded and the corrosion products were carefully brushed off for analyses. The coupons were cleaned using standard procedures recommended by [15]. They were immersed in toluene for four hours and were subsequently rinsed with acetone. Thereafter they were immediately dried with a gentle air stream and weighed to within + 0.1mg using an Ohaus digital balance. In some cases, the coupons were cleaned by immersion in 15% inhibited hydrochloric acid to remove corrosion products. An inhibitor stock solution was made of 37.5% HCl to which 10g/l of 1-3di-n-butyl-2 thiourea (DBT) had been added. At the time of the retrieval of the coupons the readings of the electrical resistance probes were also taken. Corrosion rates were calculated in line with [15] interpretation of corrosion coupons test data procedure.

### III. RESULTS AND DISCUSSIONS

The coupons in the lines were all retrieved at the monitoring times and were replaced with fresh coupons. There were no deliberate attempts to specifically fix the coupons extraction times to conform to regular time intervals. Corrosion rates were put together from different monitoring campaign data. Generally, when well conditions do not markedly alter with time the corrosion rates took the pattern shown in Fig. 4. The rates diminished with time as the adherent corrosion products progressively and effectively provided barriers to further metal dissolution. Generally, when well conditions alter with the variations of the concentrations of the constituents like water content, CO<sub>2</sub> content, pressure values, temperature etc, corrosion rates vary and the smooth corrosion-time curve decrease shown in Fig. 4, is not obtained. Fig. 5, 6 and 7 show typical corrosion patterns prevalent in the lines monitored.

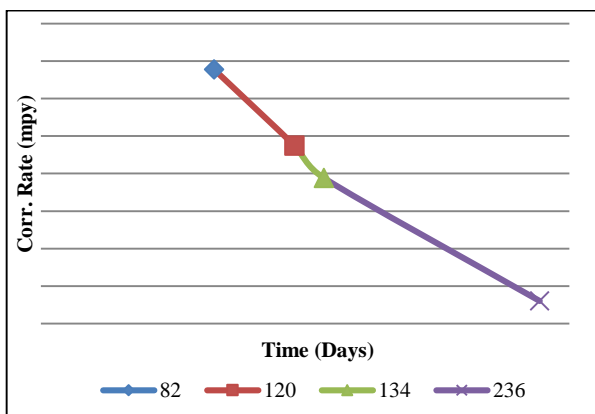


Fig. 4. Corrosion rates for coupons wholly extracted and analyzed at different times for CMP 28 (Well 25L Gas Line)

Fig. 5 to 7 presented troughs and subsequent corrosion rate increases. These are indicative of fluctuations in fluid concentrations and changes in operational parameters.

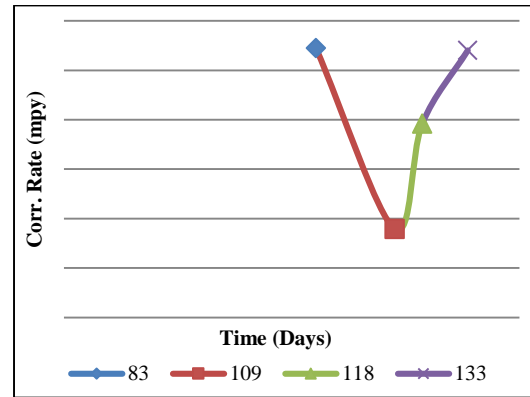


Fig. 5. Corrosion rates for coupons wholly extracted at different times for CMP 10 (6in. diam. glycol dehydration regeneration gas inlet to fan cooler)

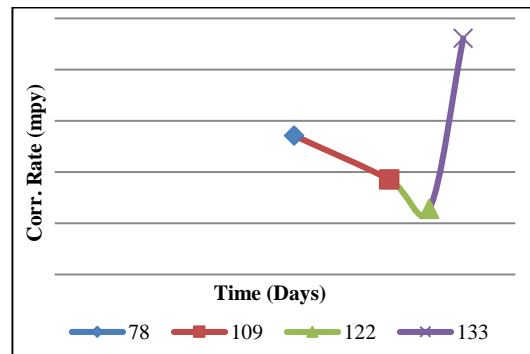


Fig. 6. Corrosion rates for coupons wholly extracted at different times for CMP 06 18in. Gas Inlet Line

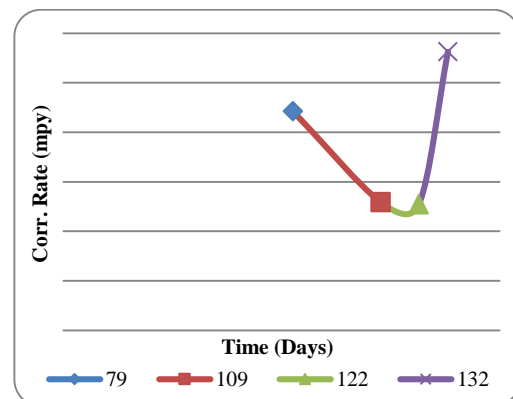


Fig. 7. Corrosion rates for coupons wholly extracted at different times for CMP 08 (24in. Gas arrival Line)

A corrosion grid was developed to explain the fluctuations in corrosion rates that were observed in the oil and gas operations in the Niger Delta of Nigeria.

### IV. CORROSION ANALYSIS GRID

Typical results obtained for installations in a station are given in a grid (Fig. 8) incorporating the corrosion rates of the coupons and coupons' physical in situ presentation. Some corrosion rates trends are visible from the grid. Coupons in cmp 01, cmp 03 and cmp 09 with the sticky waxy corrosion- inhibition- imparting covering have corrosion rates in the range of 0.1997mpy to 0.3075mpy. With the incidence of water, brownish superimposition on the otherwise dark background occurred with a corrosion rate rise. This is the case for coupons in cmp 07, cmp 08, cmp10 and cmp 22. Their corrosion rates are in the range of 0.3769mpy to 0.8427mpy. In cases where particulate matter was presented leading to erosion corrosion, further increase

in corrosion rate was experienced. This was so for coupons in cmp 06 and cmp11 where the corrosion rates ranged from 0.9098mpy to 1.6244mpy. Corrosion rate mechanism patterns are clearly deducible from this presentation.

Gas medium	Cmp 01	Q843	0.3075mpy	dark slightly sticky oil covering
		Q844	0.1997mpy	
	Cmp 03	145	0.2925mpy	dark slightly sticky oil covering
		146	0.2695mpy	
	Cmp 06	Q774	0.9098mpy	dark, sooty with brownish & whitish shiny spots
		Q775	0.9365mpy	
	Cmp 07	Q791	0.4110mpy	dark sooty film with brownish superimposition
		Q773	0.3769mpy	
	Cmp 08	Q776	0.5062mpy	uniform brownish coloration with tiny greyish spots
		Q777	0.6186mpy	
	Cmp 09	Q778	0.2081mpy	clean, with thin waxy covering
Q779		0.2033mpy		
Cmp 10	Q780	0.5052mpy	dark, sooty with oil and water droplets	
	Q792	0.5754mpy		
Cmp 11	Q781	1.2739mpy	dry, gritty, sooty with brownish superimposition	
	Q782	1.6244mpy		
Cmp 22	Q99	0.8427mpy	dry, dark and sooty coupons with clusters of greyish patches	
	100	0.7326mpy		
Glycol	Cmp 02	143	0.1861mpy	clean, with waxy covering and some sooty particles scattered on coupons' surfaces
		144	0.2709mpy	
	Cmp 04	147	0.2156mpy	clean, with waxy covering and some sooty particles scattered on coupons' surfaces
		148	0.2717mpy	
Water	Cmp 05	149	5.0748mpy	brownish with thick rusty layers
		150	4.5091mpy	
	Cmp 21	Q753	42.7080mpy	brownish with thick rusty layers
		Q754	41.0115mpy	

Fig. 8. Corrosion Analysis Grid for some Lines for Coupon Immersion Times of between 127 to 134 Days (Cmp – corrosion monitoring point)

## V. CORROSION MECHANISMS

Three main corrosion mechanisms are proposed to be active for the coupons located in the gas medium of the flow lines. The first is oxidation of the metal by the hot gas. This is evidenced by the preponderance of the coupons' dark coloration that is essentially a combination of thin scale and sooty deposits. Secondly it is clear also that the gases from the different locations are laden with moisture at different concentrations. This is attested to by the superimposing brown coloration and by the water droplets that remain on the coupons. Indeed, basic sludge and water are present in some of the lines. Water incidence in the gases leaves in its wake an aqueous corrosion additive. The aqueous corrosion component can be exacerbated by the incidence of CO<sub>2</sub> gas that dissolves in the water to form carbonic acid. Carbonic acid provides a reservoir of H<sup>+</sup> ions at a given pH. The H<sup>+</sup> ions thereafter go through a series of reactions to produce hydrogen gas. The effect is that cathodic depolarization further assists the anodic Fe dissolution. The third corrosion mechanism is erosion corrosion occasioned by the blasting effect of the high velocity particulate matter that impinge on the coupons and indeed the walls of the pipes. The appreciably high operating pressures in excess of say 70 bars impact on sand particles and indeed the gas molecules themselves sufficient velocities to leave in their wakes shiny spots on some of the coupons. These shiny spots on dry coupons are indicative of a pseudo-cleaning blasting effect of the fast moving particles.

Fortunately, in some cases, a measure of inherent corrosion inhibition is provided by condensate and atomized oil droplets in the fast moving gas. Again this is evidenced by the sticky or oily covering on some of the coupons with the attendant corrosion rate attenuation. Some pictorial

presentations of the coupons are shown in Fig. 9 to 11.



Fig.9. CMP 05; coupons immersed in recirculation water line. View immediately after extraction, campaign 1, dark brownish scales and water covering; average corr. rate, 2.7472 mpy



Fig. 10. CMP 09; gas medium; Smooth, waxy, ash coupons' surfaces, Corr. rate, 0.2033 mpy. View immediately after extraction.



Fig. 11. CMP 07; gas medium; Dark sooty film with slight brownish superimposition, Corr. Rate, 0.4110 mpy, 0.3769mpy; View immediately after extraction.

Understandably the coupons in contact with water, Fig. 9, showed relatively highest corrosion rates. The rate was as high as 5.0748 mpy but was effectively reduced to 2.7472 mpy by corrosion inhibitor application.

## VI. ER – PROBES DATA CONTRIBUTION TO THE CORROSION RATE ANALYSES

Once installed the ER probes remain in the lines for years until the successive “check” readings alter markedly, i.e., until the readings are compromised. In essence they are not removed and fresh ones reinstalled like the coupons in the few monthly corrosion monitoring campaign intervals. Being in the lines for longer times than the coupons direct comparison of their corrosion data with those of the coupons are therefore not strictly feasible. When however, the ER probes readings are taken at times coincident with the coupons resident times in the lines the corrosion rates are approximately similar. They therefore provided excellent data for comparison with the coupons' corrosion data.



Furthermore, they provide data for the real time corrosion analyses of lines over extended periods of time. For the majority of the lines the corrosion rates tend to zero for long periods of about six months and more. This is indicative of active passivation of the lines by the tenaciously adhering corrosion films and explains why most of the lines have held out for over twenty years without the incidence of significant leakages or breakouts. A representative figure of this scenario is given in Fig. 12.

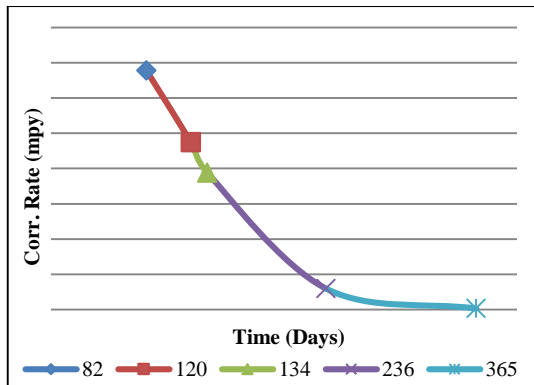


Fig 12. Modification of fig. 4; Corrosion rates for coupons extracted and analyzed at different times and merged with one ER probe corrosion rate figure (last point at 365 days); for CMP 28 (Well 25L Gas Line)

The ER probe corrosion rate figure for CMP 28 has been incorporated into Fig. 4 to obtain Fig.12.

## VII. CONCLUSION

- Internal corrosion of carbon steel pipes transporting oil and gas in the Niger Delta region of Nigeria has been carried out using carbon steel coupons and electrical resistance probes
- The incidence of corrosion was detected for the pipes investigated with corrosion attenuation to near zero level in some cases, that could be said to contribute to the increase in pipes' life spans beyond the estimated values. Corrosion mechanisms for the lines vary in line with the fluid content and operational parameters
- Corrosion mechanisms for the lines varied in line with the fluid content and Operational parameters. Three internal corrosion modes were identified. These were oxidation of the pipes by hot gases associated with natural gas extraction, erosion corrosion by high velocity particulate matter in the gas train and aqueous corrosion occasioned by the water present in the oil and gas extracted. The latter in some instances had dissolved CO<sub>2</sub> gas and this exacerbated the aqueous corrosion presentation. The three corrosion modes acted separately or synergistically to exacerbate the corrosion attack.
- Sour corrosion was not identified in all the cases investigated.

- The dual corrosion monitoring technique employed proved very effective in prompt determination of 'local hot spots', i.e., where corrosion rates were high. These data assisted in institution of inhibition regimes and other remedial actions as the case may be. Effective inhibition regime using inhibitors of the amine group in an instance markedly lowered the corrosion rate of a line from 42.7080mpy to 1.3447mpy.
- The ER probes incorporation offered a comparative corrosion monitoring alternative that provided insight into the real time conditions of the pipelines over prolonged periods of times.

## VIII. RECOMMENDATION

The above procedure is not extensively employed by the oil and gas industry stake holders in Nigeria. Implementation of real life (i.e. not virtual) onsite corrosion monitoring regimes by oil and gas stake holders is therefore advocated as this will immensely assist in lowering incidents of ruptures and leaks to the barest minimum.

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