

Investigate the Synergism of Acetic Acid and Ethylene-Glycol on Pipeline Steel Corrosion in CO₂ Saturated Environment

¹Ikeh, L and ²Dune, K.K

¹Department of Petroleum and Gas Engineering, University of Port Harcourt, Nigeria.

²Department of Petroleum Engineering, Rivers State University, Nkpolu, Port Harcourt.

Corresponding Author: nda_sor@yahoo.com

Abstract

Scale and Wax depositions are one of the major causes of corrosion problems in the oil and gas industry. They can lead to production and/or operational shutdown as well as revenue loss. Corrosion/scale depositions can occur in production equipment and surface facilities especially in flow line casing. In addition, deposition of scale in oilfield can plug oil and gas production lines, pumps, tubing and reduces the flow of fluid through the pipelines. Different work had been published on the corrosion of carbon steel in CO₂ environment, but not enough have been seen on the effects of HAc and MEG in CO₂ saturated environment. In this paper, the combined effects of HAc on corrosion of carbon steel in CO₂ saturated environment were investigated at 25°C and 80°C especially when different concentrations of MEG were added repeatedly using 3.5% wt. NaCl solution in a semi-circulated loop setup. Weight loss method and electrochemical measurements using linear polarization resistance (LPR) were used to evaluate the reactions and efficiencies of HAc and MEG on the carbon steel corrosion at different temperatures and concentrations. The results obtained show that MEG is found to be very effective in reducing the corrosion rate of carbon steel in the presence of HAc at different conditions tested. The corrosion rate reduced drastically on addition of 20% and 80% MEG concentration to the solution, compared to when only HAc was presence. A more satisfactory results were obtained with the 80% MEG at both temperatures where the corrosion rates decreases from 0.70 mm/yr to 0.32 mm/yr and fom 0.38 mm/yr to 0.11 mm/yr respectively.

Key words: CO₂ corrosion, carbon steel, acetic acid, MEG, scale deposition.

Introduction

Natural gas usually contains about 20 – 100 lbm of water per MMSCF of gas, depending on the saturated point at the operating conditions. Pipeline failures due to corrosion could be very costly in terms of safety, cost or environmental damage [1]

Carbon steel are preferably used to transport oil and gas products from the well over long distances because of cost and its availability. Apart from oil/or gas been transported in the pipeline, it is common that wells produce other products that are likely to cause corrosion, such as water (H₂O), carbon dioxide (CO₂), hydrogen sulphide (H₂S) and acetic acid (CH₃COOH). However, the processing and transportation of this gas is hindered by corrosion due to water content and formation of gas hydrates in pipelines. Water can condense along the pipeline due to temperature difference between the source and process plant which invariably can lead to more corrosion and gas hydrate formation [2].

MonoEthylene glycol (MEG) most time is injected into the pipeline to lower the freezing point as well as reducing the corrosion rate of the pipeline. Thermodynamic hydrate inhibitors are at times applied to prevent the formation of hydrates that can block the pipelines in most gas production system. More importantly, MEG has an advantage of inhibitor prevention because it is less toxic when compare to methanol and has low density [3-6]. Besides, MEG has corrosion inhibition properties, but the corrosion inhibition of MEG is normally not enough to protect the carbon steel used in the construction of oil and gas pipeline [5].

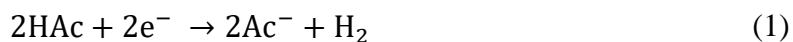
Iron carbonate scale that forms on the carbon steel in CO₂ environments is a frequent concern in the oil and gas production and transportation industry. The iron carbonate film can slow the corrosion process by presenting a diffusion barrier for the species involve and covering up a portion of the steel surface as well as preventing the underlying steel from further dissolution. However, the steel surface corrodes under the film continuously creating a void between the film and the steel surface [7]

Many studies had been devoted on corrosion of carbon steel in CO₂ environment, but none emphasizing on the conditions when acetic acid and MEG are present. Gulbrandsen et al [5] in their work reported that MEG altered the anodic half reaction of the corrosion process or dissolution of iron. They related the results to the possible adsorption of MEG on the steel surface. The corrosion rate of steel in the presence of MEG can be lower compared to that without MEG [5, 8]. De Waard and Milliams [8] demonstrated that addition of glycol to wet gas pipeline influenced CO₂ corrosion by lowering the dew point of water and consequently could reduce the severity of Top-of-the-line corrosion. He further explained that the corrosion rate at the bottom of the line decreases when glycol mixes with the water phase [2, 5, 6, 8, 9]. The influence of other parameters such as O₂, H₂S in continuation with MEG had been studied, but the effects of acetic acid are yet to be understood [5, 6, 9, 10].

Similarly, the use of pH stabilization in MEG-containing system has successfully been implemented in the multiphase transportation of natural gas [2, 3, 6]. The pH stabilization reduces the cathodic reaction

of the corrosion of steel while encouraging the formation of protective iron carbonate on the surface of the carbon steel pipeline. Meanwhile, when formation water is produced from the well, pH stabilization become undesirable method for preventing corrosion as other unwanted scale may form along the pipeline [8, 11].

CO₂ corrosion in the presence of acetic acid (HAc) is known as major causes for premature failures in oil and gas pipelines that usually made of carbon steel [12]. Also, acetic acid (HAc) is often the most abundant volatile organic acids in formation water. In oilfield pipelines at low partial pressure of CO₂ (pCO₂), the corrosion issues are easily managed, but when small amounts of acetic acids are present, the corrosivity of the brine can change dramatically [13]. It has been experimentally shown that the total quantity of organic acids in produced water in oil and gas system is approximately between 500-3000 ppm of which HAc contributes about 50-90% of organic acids [14]. However, a systematic investigation of field data showed that undissociated HAc concentration higher than 0.1-1 mM was a critical factor for CO₂ corrosion [13]. Garsany et al. [15] proposed that the role of acetic acid is to act as a reactant in the cathodic process which could have a significantly higher rate than the reduction of protons or carbonic acid in oilfield conditions. The three main cathodic reactions involving acetic acid are given below [15]:



From equation (3), the reaction mechanism and kinetics of the iron dissolution with the overall reaction are affected by acetic acid, CO₂ partial pressure and pH [16].

Dugstad [17] and Gunaltun et al. [18] in their results from field observations/laboratory investigations that the presence of HAc may induce a detrimental effect on the overall corrosion rate and the pitting morphology in sweet systems. Field experienced has also shown that HAc is a key factor in the localized top-of-line corrosion attacks in gas-condensate to pipeline [19]. Moreover, the presence of HAc also tend to solubilize the dissolving iron ions and suppress FeCO₃ formation, which can passivate the steel surface [20].

However, from the published work reviewed so far, there appeared to be many unanswered questions on how MEG affect the CO₂ corrosion mechanism during film formation in the presence of HAc. This paper looks at the corrosion rate of carbon steel under the influence of acetic acid and monoethylene glycol during film formation and dissociation.

Description and Application of Equipment and Processes.

The experiments were performed in a mini circulation flow loop. A peripheral pump circulates the test solution from the reservoir to the test cell. A small diameter pipe maintained a constant liquid volume flow in the cell. The reservoir tank and the test cell were continuously purged with CO₂ to removed oxygen completely from the test solution. Once de-oxygenation has been achieved, the required amount

of HAc, MEG and inhibitors were added at the start of every experiment. The temperatures were controlled by means of a heating plate with a temperature sensor in the cell. The pH of the solution was adjusted to the desired value throughout the experiments by adding sodium bicarbonate (NaHCO₃) or hydrochloric acid (HCl) as required.

Test set up and procedures

The test specimens used entirely for this study are carbol steel with a surface area of 8.11cm² and a circular hole toward the top end. A copper wire of 0.02 mm diameter was spot welded and used on the test coupons to ensure electrical contact between the electrode and electrolyte. The test coupons were suspended in the test solution by passing a plastic wire through the coupon and the wire was hung to a plastic rod held in place of the glass cell top holes. Prior to introduction into the test cell, the test coupons were successively ground with 240, 600 and 800 SiC grit paper and polished with 1200 SiC paper. It was then cleaned with acetone, rinsed with distilled water and dried. The general composition of the carbon steel samples used in this work is given in Table 1.

Four test solutions were prepared. The first test solution was prepared with 3.5% wt. sodium chloride (NaCl) as the blank solution without HAc and MEG. The second test solution was prepared using 3.5% NaCl solution and 1000ppm, 2000ppm, 3000ppm and 4000ppm of HAc without MEG. The third test solution was prepared using 3.5% NaCl solution, 1000ppm, 2000ppm, 3000ppm and 4000ppm of HAc and 20% MEG, while the fourth test solution was prepared using 3.5% NaCl, 1000ppm, 2000ppm, 3000ppm and 4000ppm of HAc and 80% MEG respectively. Table 3 summarizes the composition of test matrix used for this study.

Table 1: Chemical composition of mild steel (wt. %).

Comp.	C	Si	Mn	S	P	Sn	Cr	Ni	Mo	Cu	Al
Val. %	0.08	0.25	1.54	0.001	0.019	0.008	0.04	0.03	0.01	0.12	0.038

Table 2: Compositions of the test matrix used for the experiments [21]

Parameters	Values
Test solution	3.5% wt. NaCl
Test material	Carbon steel
Partial pressure of CO ₂ (bar)	0.54
MEG concentrations	[20%, 80%]
pH	6.6
Temperature (°C)	[25, 80]
C _{HAc} (ppm)	[0, 1000, 2000, 3000]

Surface area (cm ²)	8.11
Test method	[WL, and LPR]

Measurement Techniques

The weight loss and linear polarization resistance measurement methods were performed on the carbon steel samples in all the test solutions at temperatures of 25°C and 80°C respectively. The weight loss is measured, determined and the corrosion rate calculated by applying Equation 1:

$$= \frac{WL(g)}{\rho \times t \times A} \times K \left(\frac{mm}{yr} \right) \tag{1}$$

Where:

CR = corrosion rate, mm/yr,

ρ = density of the material, 7.86 g/cm³

WL = weight loss, grams,

t = the exposed time, hr

A = the exposed coupon surface area, cm²,

K = conversion factor, 8.76×10⁴

However, the electrochemical measurements were carried out using a commercial potentiostat. A three-electrode configuration was used in all the measurements. The carbon steel sample was used as the working electrode, while the Ag/AgCl wire was used as reference electrode. The linear polarization curves were obtained in the potential range of -10 to +10 mV (vs. E_{corr}) with a scan rate of 0.1 mV/s.

Results and Discussion

Weight loss test

The weight loss results for the first set of experiments (3.5% wt. NaCl without HAc, and MEG), the second test solution (3.5% wt. NaCl with 1000ppm, 2000ppm, and 3000ppm HAc and without MEG), the third test solution (3.5% wt. NaCl with 1000ppm, 2000ppm, 3000ppm HAc and 20% MEG), the fourth test solution (3.5% wt. NaCl with 1000ppm, 2000ppm, 3000ppm HAc and 80% MEG) evaluated at 25°C and 80°C are presented in Figures 1 to 6 and are summarized in Table 3 to Table 8 respectively.

Experiment with HAc

Figure 1 and Figure 2 shows the relationship between the average corrosion rate of carbon steel pipeline against time in a solution containing 3.5% wt. NaCl and at different concentrations of HAc at 25°C and

80°C respectively.

At 25°C (Figure 1), the corrosion rate increased drastically over time as the concentrations of HAc increases. As can be seen, the corrosion rate for the blank solution (solution without HAc) is approximately 0.35 mm/yr. On addition of 1000ppm HAc, the corrosion rate increases drastically from 1.30 mm/yr to 1.76 mm/yr for period of two hours in the solution. Further addition of 2000 ppm and 3000 ppm of HAc to the solution raises the corrosion rate to approximately 1.65 mm/yr and 1.80 mm/yr after 14 hours duration in the solution.

Similarly, at 80°C (Figure 2), the corrosion rate also increases over time as different concentrations of HAc were added to the solution. As can be seen from Figure 2, the corrosion rate increased from about 1.05 mm/yr to approximately 2.80 mm/yr on addition of different concentration of HAc to the system. Though, the corrosion increases rapidly at both temperatures, it is however higher at 80°C than at 25°C. This higher increased in corrosion rate in high temperature is caused as a result of fast reaction rate that usually occurs at higher temperatures. Similarly, it is also assumed that a protective Iron carbonate (FeCO₃) scale are formed and however remain protective in the presence of HAc provided the supersaturation is at maximum to sustain the protective films formed. Tables 3 and 4 presents the summary of the average weight loss per unit area for the carbon steel used for the experiments at 25°C and 80°C respectively.

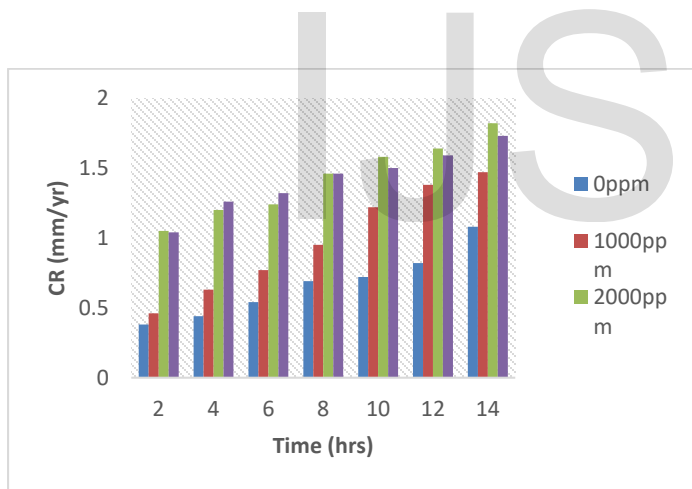


Figure 1: Effect of HAc on corrosion rate of carbon steel as a function of time in 3.5% wt. NaCl solution at 25°C

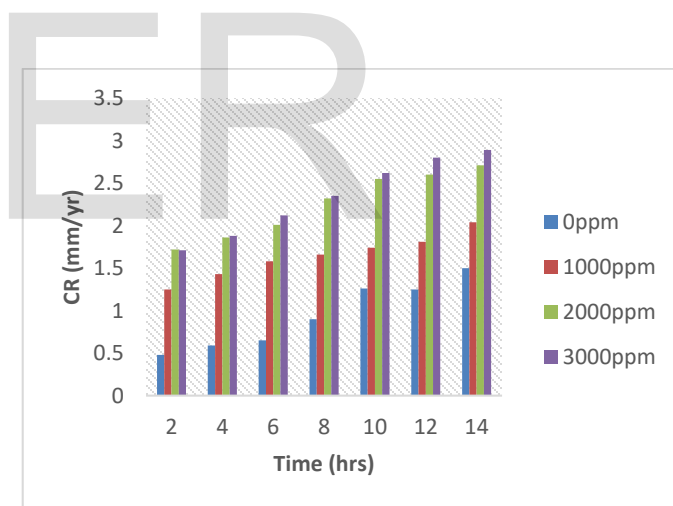


Figure 2: Effect of HAc on corrosion rate of carbon steel as a function of time in 3.5% wt. NaCl solution at 80°C.

Table 3: Average corrosion rate as a function of time for carbon steel corrosion in the presence of HAc at 25°C and 80°C respectively.

T= 25°C					T= 80°C						
		HAc Conc, ppm						HAc Conc, ppm			
T(hrs.)	0	1000	2000	3000	T(hrs.)	0	1000	2000	3000		
2	0.38	0.46	1.05	1.04	2	0.48	1.25	1.72	1.71		

4	0.44	0.63	1.2	1.26	4	0.59	1.43	1.86	1.88
6	0.54	0.77	1.24	1.32	6	0.65	1.58	2.01	2.12
8	0.69	0.95	1.46	1.46	8	0.9	1.66	2.32	2.35
10	0.72	1.22	1.58	1.5	10	1.26	1.74	2.55	2.62
12	0.82	1.38	1.64	1.59	12	1.25	1.81	2.6	2.8
14	1.08	1.47	1.82	1.73	14	1.5	2.04	2.71	2.89

Experiment with HAc and MEG

Figure 3 to Figure 6 shows the corrosion rate of carbon steel pipeline against time in a solution containing 3.5% wt. NaCl with HAc and 20%/80% MEG at 25°C and 80°C. As observed from the results (Figure 3 – Figure 6), the introduction of MEG (20% and 80%) had significant influenced in reducing the corrosion of carbon steel materials.

At 25°C and 20% MEG (Figure 3), the corrosion rate reduces drastically from 1.92 mm/yr to 0.78 mm/yr for the 14 hours duration of the test. Similarly, at 25°C and 80% MEG (Figure 4), the corrosion rate also decreases with time from about 3.5 mm/yr to approximately 0.65 mm/yr for the same period of time in the solution.

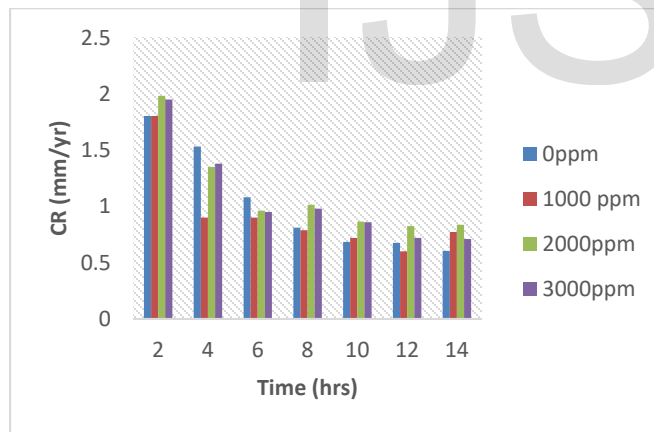


Figure 3: Combined effect of HAc and 20% MEG on corrosion rate of carbon steel as a function of time in 3.5% wt. NaCl solution at 25°C.

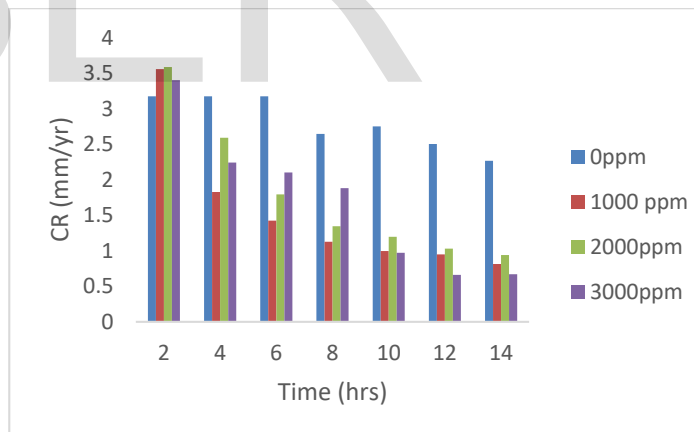


Figure 4: Combined effect of HAc and 80% MEG on corrosion rate of carbon steel as a function of time in 3.5% wt. NaCl solution at 25°C.

Table 4: Average corrosion rate as a function of time for carbon steel corrosion in the presence of HAc and different concentrations of MEG at 25°C respectively

T= 25°C, 20% MEG					T= 25°C, 80% MEG				
HAc + MEG					HAc + MEG				
T(hrs.)	0	1000	2000	3000	T(hrs.)	0	1000	2000	3000
2	1.80	1.80	1.98	1.95	2	3.17	3.55	3.58	3.4

4	1.53	0.90	1.35	1.38	4	3.17	1.82	2.58	2.24
6	1.08	0.90	0.96	0.95	6	3.1	1.42	1.79	2.1
8	0.81	0.78	1.01	0.98	8	2.64	1.12	1.34	1.88
10	0.68	0.720	0.86	0.86	10	2.74	0.99	1.19	0.97
12	0.67	0.60	0.82	0.72	12	2.50	0.94	1.02	0.66
14	0.60	0.77	0.83	0.71	14	2.26	0.81	0.93	0.67

At 80°C and 20% MEG (Figure 5), the average corrosion rate after 14 hours in solution decreases from 3.05 mm/yr to about 0.76 mm/yr and from 2.0 mm/yr to 0.98 mm/yr at 80°C and 80% MEG (Figure 6). The continues decreased in corrosion rate on addition of different concentrations of MEG to the solution is caused by the reduction in pH of the solution. Tables 7 and 8 shows the summary of the average corrosion rate with time for the carbon steel samples in the presence of different concentrations of HAc and MEG respectively.

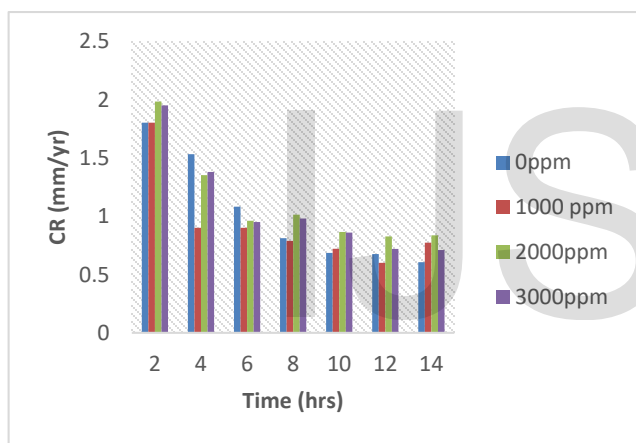


Figure 5: Combined effect of HAc and 20% MEG on corrosion rate of carbon steel as a function of time in 3.5% wt. NaCl solution at 80°C.

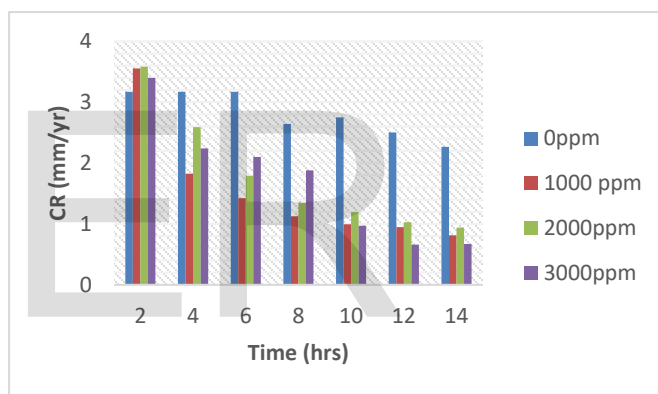


Figure 6: Combined effect of HAc and 80% MEG on corrosion rate of carbon steel as a function of time in 3.5% wt. NaCl solution at 80°C.

Table 5: Average corrosion rate as a function of time for carbon steel corrosion in the presence of HAc and different concentrations of MEG at 80°C respectively

T= 80°C, 20% MEG					T= 80°C, 80% MEG				
HAc + MEG					HAc + MEG				
T(hrs.)	0	1000	2000	3000	T(hrs.)	0	1000	2000	3000
2	1.80	1.80	1.98	1.95	2	3.17	3.55	3.58	3.4
4	1.53	0.90	1.35	1.38	4	3.17	1.82	2.58	2.24
6	1.08	0.90	0.96	0.95	6	3.17	1.42	1.79	2.1
8	0.81	0.78	1.01	0.98	8	2.64	1.12	1.34	1.88
10	0.68	0.72	0.86	0.86	10	2.74	0.99	1.19	0.97
12	0.67	0.60	0.82	0.72	12	2.50	0.94	1.02	0.66
14	0.60	0.77	0.83	0.71	14	2.26	0.81	0.93	0.67

Results with LPR

The performance of different concentrations of HAc and MEG on the corrosion rate of carbon steel pipeline in CO₂ saturated environment at temperatures of 25°C and 80°C were also evaluated using the electrochemical measurement technique (LPR).

At 25°C, (Figure 7), The corrosion rate increases with increase in time as was expected. At 0ppm of HAc, the corrosion increases rapidly from about 0.34 mm/yr to 0.92 mm/yr after 10hours test duration. The addition of 1000ppm, 2000ppm and 3000ppm of HAc raised the corrosion from 0.65 mm/yr to 1.20 mm/yr, 0.61 mm/yr to 1.45 mm/yr and from 0.75 mm/yr to 1.62 mm/yr respectively.

At 80°C (Figure 8), the corrosion rate also increases with increased in concentrations of HAc compared to the blank solution. At 0 ppm of HAc, the corrosion rate moved from 0.4mm/yr to 1.2 mm/yr. Addition of 1000ppm, 2000ppm and 3000ppm of HAc increases the corrosion rate from 0.85mm/yr to 1.4 mm/yr, 0.8 mm/yr to 1.65 mm/yr and from 0.85 mm/yr to 1.83 mm/yr respectively.

However, the introduction of 20% MEG and 80% MEG drastically decreases the corrosion rate to a minimum level. At 25°C (Figure 7), the corrosion rate decreases from 0.60 mm/yr to 0.35 mm/yr on addition of 20% MEG and from 0.40 mm/yr to 0.15 mm/yr on addition of 80% MEG to the solution. Similarly, at 80°C (Figure 8), the corrosion decreases from 0.70 mm/yr to 0.32 mm/yr on addition of 20% MEG to the system and from 0.38 mm/yr to 0.11 mm/yr on after adding 80% MEG to the solution. However, this reduction in corrosion rate prove that corrosion reaction is inhibited by addition of 20% MEG and 80% MEG to the solutions. As it is observed, the corrosion rate for the inhibited samples reduces drastically to less than 0.4 mm/yr compared to the uninhibited samples with HAc only.

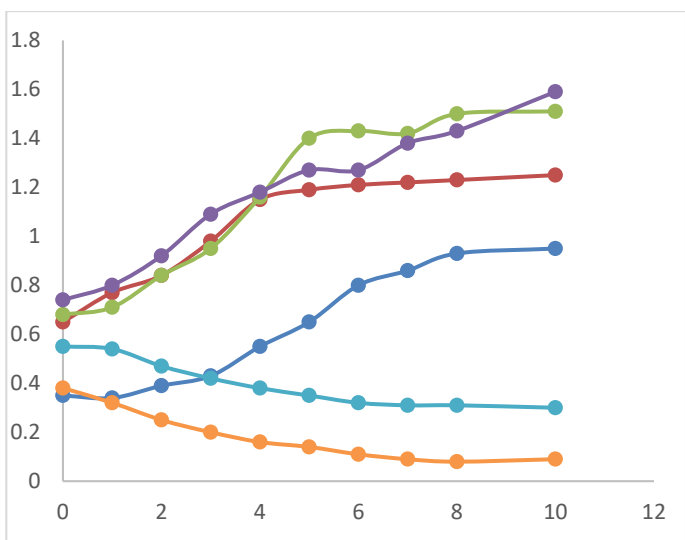


Figure 7: Performance of HAc and 20% MEG on corrosion rate of carbon steel sample as a function of time in 3.5%

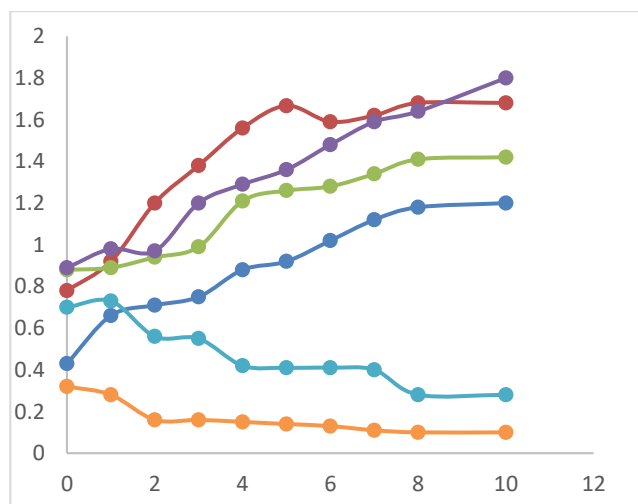


Figure 8: Performance of HAc and 20% MEG on corrosion rate of carbon steel sample as a function

wt. NaCl solution at 25°C.

of time in 3.5% wt. NaCl solution at 80°C

Conclusions

In this work, the combined effect of various concentrations of HAc and MEG on corrosion rate of carbon steel in CO₂ saturated environment were evaluated at 25°C and 80°C, pH of 6.6, and CO₂ partial pressure of 0.54 bar. The results obtained so far showed changes in mechanism of corrosion rate with time at different concentrations of HAc and MEG studied.

The weight loss method gives a more reliable results of the corrosion rate as a function of time for the carbon steel tested. It is seen that the presence of HAc in the solution of 3.5% wt. NaCl increases the corrosion rate at both temperatures for the entire duration of the test but, addition of 20% and 80% MEG concentrations decreased the corrosion rate rapidly to a minimum level of about 0.15 and 0.35 mm/yr respectively.

The application of electrochemical measurements also showed similar results to that of the weight loss method. It can be observed that the corrosion rate on addition of 20% and 80% MEG reduces the corrosion rate for all the conditions tested. A more satisfactory results were obtained with the 80% MEG at both temperatures where the corrosion rates decreases from 0.70 mm/yr to 0.32 mm/yr and from 0.38 mm/yr to 0.11 mm/yr respectively.

Acknowledgments.

The authors would like to thank the University of Port Harcourt and the Rivers state University for their support for this work

Nomenclature

HAc	Acetic acid
MEG	Monoethylene glycol
Ppm	Parts per million
Mm/yr	Millimetres per year

References.

1. Executive, H.a.S.L.f.t.H.a.S., *Reliable corrosion inhibition in the oil and gas industry*. HSE, 2014.
2. Gonzalez, J.J., M.E. Alfonso, and G. Pellegrino, *Corrosion of Carbon Steels in Monoethylene Glycol*. NACE International.
3. Elhady, A.A.A., *Operating Experiences of DEG and MEG for Hydrate and Dewpoint Control in Gas Production Offshore Mediterranean*. German National Library of Science and Technology, 2006.
4. Brustad, S., K.P. Løken, and J.G. Waalman, *Hydrate Prevention using MEG instead of MeOH: Impact of experience from major Norwegian developments on technology selection for injection and recovery of MEG*. Offshore Technology Conference.
5. Gulbrandsen, E. and J.H. Morard, *Why Does Glycol Inhibit CO₂ Corrosion?* NACE International.

6. Wang, C., et al., *Corrosion Study of Carbon Steel in the Presence of Monoethylene Glycol (MEG) and Corrosion Inhibitors in Acid*. NACE International.
7. Sun, W., K. Chokshi, and S. Nestic, *Iron Carbonate Scale Growth and the Effect of Inhibition in CO₂ Corrosion of Mild Steel*. NACE International.
8. de Waard, C., U. Lotz, and D.E. Milliams, *Predictive Model for CO₂ Corrosion Engineering in Wet Natural Gas Pipelines*. Corrosion, 1991. **47**(12): p. 976-985.
9. Kvarekval, J., S. Olsen, and S. Skjerve, *The Effect of O₂ on CO₂ Corrosion in pH Stabilized Gas/Condensate Pipelines*. NACE International.
10. Kvarekvål, J. and A. Pedersen, *An Electrochemical Study of Corrosion Inhibition of Carbon Steel in Sour Glycol Solutions*. NACE International.
11. Dugstad, A., M. Seiersten, and R. Nyborg, *Flow Assurance of pH Stabilized Wet Gas Pipelines*. NACE International.
12. George, K. and S. Nestic, *Investigation of carbon dioxide corrosion of mild steel in the presence of acetic acid - part 1: Basic mechanisms*. Corrosion Science, 2007(63): p. 178-86.
13. Crolet, J.-L. and M.R. Bonis, *Prediction of the Risks Of CO₂ Corrosion in Oil and Gas Wells*. SPE Production Engineering, 1991. **6**(4): p. 449-453.
14. Gunaltun, Y. and L. Payne, *A New Technique for the Control of Top of the Line Corrosion: TLCC-PIG*. 2003, NACE International.
15. Garsany, Y., D. Pletcher, and B. Hedges, *"Speciation and electrochemistry of brines containing acetate ion and carbon dioxide"*. J. Electronal. Chemistry,, 2002. **538-539**: p. 285.
16. Crolet, J.L., A. Dugstad, and N. Thevenot, *Role of Free Acetic Acid on the CO₂ Corrosion of Steels*. 1999, NACE International.
17. Dugstad, A., *Fundamental Aspects of CO₂ Metal Loss Corrosion - Part 1: Mechanism*. 2006, NACE International.
18. Gunaltun, Y.M. and D. Supriyatman, *Top of the Line Corrosion in Multiphase Gas Lines: A Case History*. 1999, NACE International.
19. Gunaltun, Y.M. and D. Larrey, *Correlation with calculated water condensation rates*. NACE CORROSION 2000. **Paper no. 71**.
20. Videm, K. and A. Dugstad, *Corrosion of carbon steel in an aqueous carbon dioxide environment, Part 2: Film formation*. Materials Performance, 1989: p. 46-50.
21. Ikeh, L., G.C. Enyi, and G.G. Nasr, *Inhibition Performance of Mild Steel Corrosion in the Presence of Co₂, HAc and MEG*, in *SPE International Oilfield Corrosion Conference and Exhibition*. 2016, Society of Petroleum Engineers: Aberdeen, Scotland, UK. p. 10.