AN INVESTIGATION ON THE ENHANCED OIL RECOVERY PERFORMANCE OF LOCAL BIOPOLYMERS

Abstract

The introduction of polymers into the reservoir yields favorable mobility ratio between the entrapped crude and injected water to improve sweep efficiency and incremental recovery of the reservoir. Xanthan Gum is the most widely utilized bio-polymer for chemical enhanced oil recovery (CEOR), but the polymer is imported. However, recent studies have shown the potentials of local bio-polymers in alternating conventional polymer in CEOR. This have attracted serious interest due to their availability, low cost and eco-friendly nature. In this paper a comparative CEOR investigation was conducted between conventional and local polymers. Cook Pine Exudate (CPEG), Afzelia Africana (AA) and Terminalia Mantaly Exudate (TMEG) were used as local-polymer while Xanthan Gum (XG) was used conventional polymer. FTIR evaluation, aqueous stability, Viscosity, Adsorption and EOR core-flood study were conducted on the investigation. From the FTIR evaluation CPEG, AA and TMEG can be classified as polysaccharides. From Aqueous Stability test, CPEG, AA and TMEG formed colloidal phase with water. From the viscosity result CPEG, AA and TMEG recorded similar viscosity trend present in XG. From the Adsorption test, increase in concentration increased adsorption rate. From the CEOR study, favorable mobility ratio was achieved at 0.25wt% concentration for all polymers utilized for the study. 0.25wt% CPEG yielded the best recovery of the polymer formulation as it recorded additional 17.65% after secondary recovery, while TMEG, XG and AA recorded additional 16.67% 15% and 14.5% respectively. The study showed that CPEG, AA and TMEG can be used as alternative to XG

Keywords: Local Polymers, Enhanced Oil Recovery, FTIR, Viscosity Evaluation, Adsorption

Introduction

There is usually high residual oil saturation (ROS) in the rock formation after natural and secondary recovery phase [1], and this ROS becomes subjected of interest for the enhanced-oil-recovery (EOR) process. EOR techniques are introduced into the reservoir for the purpose of producing residual and entrapped oil [2, 3]. The EOR techniques can be grouped into non-thermal and thermal EOR. Thermal EOR is not recommended for reservoir with deeper depths, underlying aquifer or thin pay zones. This is as a result of heat loss to both overburden and under-burden layers [4]. The environmental impact concern posed by greenhouse gases is also another determinant [5] and this have resulted in the preference of EOR techniques that does not require heat. Chemical enhanced oil recovery (CEOR), a non-thermal technique have shown promising signs in improving oil recovery due to her efficiency and ease of utilization. Several reagent such as surfactant, polymer, nanoparticle and alkali have been utilized for EOR [6]. The chemicals modify the rock-fluid or/and fluid-fluid parameters of the formation to improve recovery. The rock-fluid and/or fluid-fluid interaction upgrades the sweep efficiency in the formation or yields higher pore-scale displacement effectiveness based on the type of reagent utilized [7]. Of the various CEOR techniques, polymer flooding have shown high effectiveness, unique potentials and unique properties, with oilfield applicability [8]. In polymer flooding, polymer chemicals are introduced to water and rock formation to improve viscosity of the water flood. The traditional water-flood operation without polymer introduction yields "viscous fingering", a scenario whereby the mobility of the mobilizing phase (water) and mobilized phase (oil) is above one [9], leading to early breakthrough of water. To prevent this polymer reagent are introduced during EOR to improve the viscosity of the displacing fluid to achieve favorable mobility ratio [10]. This polymers could be natural or synthetic based, and exhibits pseudo-plastic fluid behavior, with a shear-thinning viscosity (Sheng, [11]. Several polymer reagent have been utilized for CEOR but xanthan gum (biopolymer) and hydrolyzed polyacrylamide (HPAM) (synthetic) are the most used polymers [12]. PAM have significantly higher viscoelastic features than xanthan gum (XG) in fresh water but not in saline water [13]. As a result

of this, the synthetic polymer is substituted by XG which has high tolerance for salinity, mechanical shear and temperature [14]. Polymer CEOR is mostly suited for oil reservoirs with viscosity blow 100cp, temperature less than 72°C and low-moderate saline reservoir [15]. Conventional Polymer such as xanthan gum are globally accepted and utilized for CEOR, but not cost-friendly to developing countries due to importation cost. These have led to search for cheaper and available local alternatives. The successful discovery of this local alternatives will not only reduce importation but create economic value for the host country.

Ade et al [16] carried out a comparative CEOR study using gum arabic, okra and ogbonno. From their experimental analysis, okro performed better than the local polymers by recording 63.7% oil recovery while gum arabic and ogbonno recorded 53.01% and 47.3% oil recovery respectively. Ajabuego et al [17] compared the CEOR performance of archi with ogbonno and exudate gum. From their experimental analysis exudate gum yielded the best CEOR performance by recording 35.48% oil recovery while archi ad ogbonno recorded 26.67% and 31.17% recovery respectively. Abdulraheem et al., [18] study showed the potentials of local polymer substituted conventional polymers when modified as his modified gum arabic yielded 31.99% recovery unlike the natural gum arabic, xanthan gum and hengfloc which yielded 22.96%, 18.3% and 22.59% incremental recovery. Obuebite et al [19] compared the CEOR of ewedu, okro with editan. From their CEOR experimental study, okro yielded the best oil recovery. Fadairo et al [20] carried out a CEOR study between gum arabic and banana peel starch. From the CEOR study, banana peel starch performed better than gum arabic as it yielded 64.5% oil recovery while gum arabic yielded 62.6% oil recovery. Uzoho et al [21] compared abelmoschus esculentus, with irvingia gabonensis, mucuna flagelipes, detarium microcarpium and brachystegia eurycoma. From their experimental study, abelmoschus esculentus performed better than other polymers by yielding 5.2% additional displacement efficiency. Uzoho and Onyekonwo [22] compared the CEOR performance of abelmoschus esculentus with polyacrylamide. From their experimental study, abelmoschus esculentus yielded better performance than polyacrylamide as it recorded 99.1% displacement efficiency while the conventional polymer recorded 94.56%. Obuebite et al. [23] showed the potentials of Terminalia Mantaly in replacing Polyacrylamide in EOR, with the Terminalia Mantaly recorded 90% and 81% recoveries in soft and hard brine respectively. However, the effectiveness of these local polymers at prevailing condition of salinity and temperature needs to be comprehensively evaluated to confirm their ability to totally replace conventional or foreign polymer chemicals. In this study, Terminalia Mantaly Exudate (TMEG), Afzelia African (AA) and Cook Pine Exudate (CPEG) were utilized as local polymer, while Xanthan Gum (XG) were utilized as conventional polymer. FTIR Characterization, Aqueous Stability, Viscosity Test, Adsorption Test and Core-Flooding were conducted to evaluate the CEOR potentials of the locally sourced polymers. Terminalia Mantaly is a warm weather tree that grows in Nigeria, with its origin from Madagascar. Afzelia Africana plant grows in South-Eastern Nigerian, East Africa and West Coast of Africa (Senegal), in dense dry forest, wooded savannah and semi-deciduous forest areas. Cook Pine plant grows in Nigeria, with origin from Australia.

Experiment

Materials

The materials utilized for the experimental analysis includes local bio-polymer to wit; Cook Pine Exudate (CPEG), Afzelia Africana (AA) and Terminalia Mantaly (TMEG), conventional bio-polymer to wit; Xanthan Gum (XG), Industrial Salt (NaCl) and Crude Oil: Specific gravity of 0.84, API gravity of 34.97°API and viscosity of 3.753cp @ambient conditions was sourced from an Oilfield in the Niger-Delta.

Preparation of Polymers

TMEG was extracted from the incised section of the parent tree and was prepared using Michael et al [24] method. The polymer was recovered from the incised portion of a tree and dried in a lab over for 48hrs at 40°C. 100g of the dried polymer was cleansed with deionized water to eliminate foreign particles. The washed exudate gum was hydrated

in chlorofoam-water mixture for 48hrs to soften. The hydrated polymer was sieved to remove unwanted materials before drying in the over for 72hrs at 40°C. The dried gum was pulverized into smaller particles and sieved to obtain uniform particles before storing in an airtight container. CPEG was extracted from the incised section of the parent tree and solubilized in water for 24hrs. Unwanted materials were removed from the solution before been dried for 72hrs at 40°C using lab oven. The dried polymer was pulverized and sieved into finer and uniform particle before stored in an airtight container. AA pods was heated for 5 minutes at 45°C before being broken down to recover the seeds. The recovered seeds were pulverized and sieved to be recover uniform sized particles.

FTIR Characterization

Fourier Transform Infrared (FTIR) Spectroscopy was used for the characterization study. Buck 530 modelled IR-spectrophotometer was utilized for the characterization. 0.5g of the polymer chemical were mixed with 0.5g of potassium bromide (KBr) chemical powder, after which 1ml of nujol (a fluid for chemical preparation by 530 modelled IR-spectrophotometer) was introduced to the chemical reagent using syringe to form solution before it was introduced to instrument sample mould and allowed to scan at a wavelength of 600-4000cm^{-1} to derive spectra height. The FTIR spectroscopy generate plots in absorbance spectra form, which shows the unique molecular structure and chemical bonds of the selected polymer samples. The reference library program (catalogue) of the equipment used for the study, was utilized to derive the functional group present in the polymer materials

Aqueous Stability Test

To conduct fluid-fluid interaction study, a phase stability experiment on the polymers chemicals and brine solution were carried out to analyze non-homogeneity likelihoods such as phase separation, solution cloudiness and precipitate formation in the aqueous phase. CPEG, TMEG, XG and AA with concentration depicted in Table 1 were introduced into 400ml of soft brine (5000ppm) solution. The result polymer solution was introduced to 4 test-tubes labelled A, B, C, and D, and sealed to avoid loss of fluid volume. The solutions contained in the test-tube were evaluated visually, cloudy samples containing precipitates were considered incompatible and deemed to have failed the screening test as only cloudless, clear fluids were selected. The solutions were re-examined at 85°C temperature.

Table 1: Polymer Concentration

S/N	Polymer	Polymer Concentration	Brine Concentration
1	TMEG	0.25wt%, 0.5wt%, 1wt% and 2wt%	5000ppm
2	CPEG	0.25wt%, 0.5wt%, 1wt% and 2wt%	5000ppm
3	XG	0.25wt%, 0.5wt%, 1wt% and 2wt%	5000ppm
4	AA	0.25wt%, 0.5wt%, 1wt% and 2wt%	5000ppm

Polymer Viscosity Evaluation

The polymer viscosity was derived using the product of its kinematic viscosity and density. The kinematic viscosity of the polymer fluid was derived using the product of the effluent time and viscometer constant, while the fluid density was derived using density bottle test. The polymer viscosity test is utilized to evaluate the impact of salinity and temperature on the viscosity of the polymers with concentration depicted in Table 1. Table 2 and 3 depicts the brine formulation and temperature assumption utilized for the polymer viscosity study.

Table 2: Impact of Salt Concentration on Polymer Viscosity at Ambient Temperature

S/N	Polymer	Polymer Concentration	Brine Concentration
1	TMEG	0.25wt%, 0.5wt%, 1wt% and 2wt%	5000ppm, 10000ppm, 20000ppm and 30000ppm
2	CPEG	0.25wt%, 0.5wt%, 1wt% and 2wt%	5000ppm, 10000ppm, 20000ppm and 30000ppm
3	XG	0.25wt%, 0.5wt%, 1wt% and 2wt%	5000ppm, 10000ppm, 20000ppm and 30000ppm

| 4 | AA | 0.25wt%, 0.5wt%, 1wt% and 2wt% | 5000ppm, 10000ppm, 20000ppm and 30000ppm |

Table 3: Impact of Temperature Variation on Polymer Viscosity

S/N	Polymer	Polymer Concentration	Temperature Variation
1	TMEG	0.25wt%, 0.5wt%, 1wt% and 2wt%	Ambient, 35ºC, 40ºC, 45ºC, 50ºC and 55ºC
2	CPEG	0.25wt%, 0.5wt%, 1wt% and 2wt%	Ambient, 35ºC, 40ºC, 45ºC, 50ºC and 55ºC
3	XG	0.25wt%, 0.5wt%, 1wt% and 2wt%	Ambient, 35ºC, 40ºC, 45ºC, 50ºC and 55ºC
4	AA	0.25wt%, 0.5wt%, 1wt% and 2wt%	Ambient, 35ºC, 40ºC, 45ºC, 50ºC and 55ºC

Polymer Adsorption

Ultraviolet (UV) radiation method was utilized using Biomate UV Spectrophotometer. The Spectrophotometer was calibrated using its operational manual. Polymer with concentration depicted in Table 1 was agitated uniformly for 15 minute before 3hrs stabilization time was allowed. The solution was introduced into UV cell to derive absorbence of the solution. 100ml of solution was flown through 25g weigh sand-pack of uniform particle size (0.589mm size). UV study was conducted on the recovered solution to derive its new absorbance.

EOR Core-Flooding

Oil displacement evaluation was carried out to evaluate the EOR capabilities of polymer with concentrations depicted in Table 1. The bulk properties and dry core weight were derived before they were placed into the core-saturator. Brine was injected into the saturator and pressurized up-to 2500psi to reach full saturation over 48hrs period. After 48hrs, the pressure of the system were relieved before reweighing of saturated cores. The cores were placed into the core-holder shown in Figure 1 at confining pressure of 1000psi. At 2cc/sec rate, brine was introduced to ensure that the trapped air bubbles are removed and ensure 100% saturation of the core. The brine was drained out continuously by 2cc/sec rate crude oil until Swi (initial water saturation) was attained. Imbibition process was conducted with 2cc/sec rate brine until Sor (residual oil saturation) was derived during brine flooding. After the establishment of Sor, polymer flooding was then carried out. The core-flooding were carried out at ambient condition of pressure and temperature with Figure 1 showing the experimental core-flood setup
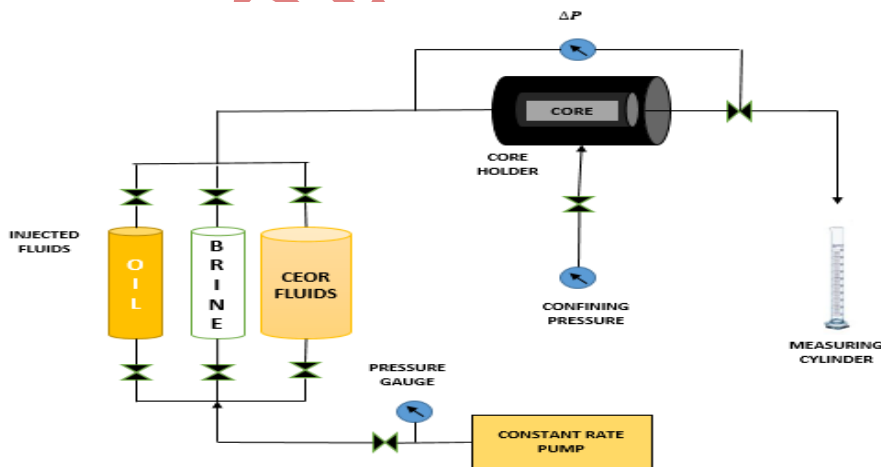

Fig 1: EOR experimental setup

Results and Discussions

FTIR Evaluation

Figures 2-5 depicts the FTIR Spectra of CPEG, TMEG, XG and AA. As shown Figure 2, the wavelength of $3804.874cm^{-1}$, $2854.287cm^{-1}$, $2538.784cm^{-1}$, $1883.881cm^{-1}$, $1419.007cm^{-1}$ and $806.2237cm^{-1}$ indicates the presence of alcohol, methylene, nitriles, carboxylic acid, ester, ethene and chloro compounds. As shown in Figure 3, the wavelength of $3697.053cm^{-1}$, $2890.022cm^{-1}$, $2481.688cm^{-1}$, $2037.26cm^{-1}$, $1899.214cm^{-1}$, $1624.910cm^{-1}$, $1382.281cm^{-1}$ and $1181.947cm^{-1}$ indicates the presence of alcohol, methylene, nitriles, carboxylic acid, ester, amine, ethene and ether compounds. As shown in Figure 4, the wavelength of at $3227.9cm^{-1}$, $2124.6cm^{-1}$, $1625.1cm^{-1}$, $1580.4cm^{-1}$, $1401.5cm^{-1}$, $1021.3cm^{-1}$ and $868.5cm^{-1}$ indicates the presence of alcohol, methylene, ester, ketones, carboxylic acid, acetate and glycoside compounds. As shown in Figure 5, the wavelength of $3692.33cm^{-1}$, $2711.43cm^{-1}$, $2517.04cm^{-1}$, $1872.581cm^{-1}$, $1395.73cm^{-1}$ and $856.853cm^{-1}$ indicates alcohol, aldehyde, carboxylic acid, aromatic, sulfonyl chloride and aromatics. As noted by Gilani et al., [25], commercial xanthan gum contains chemical groups such as acetyl ($1160cm^{-1}$), carboxyl group ($1529cm^{-1}$), carbonyl ($1627cm^{-1}$) and hydroxyl ($3386cm^{-1}$). Some of these functional present in the CPEG, AA and TMEG and this shows that they are polysaccharides.
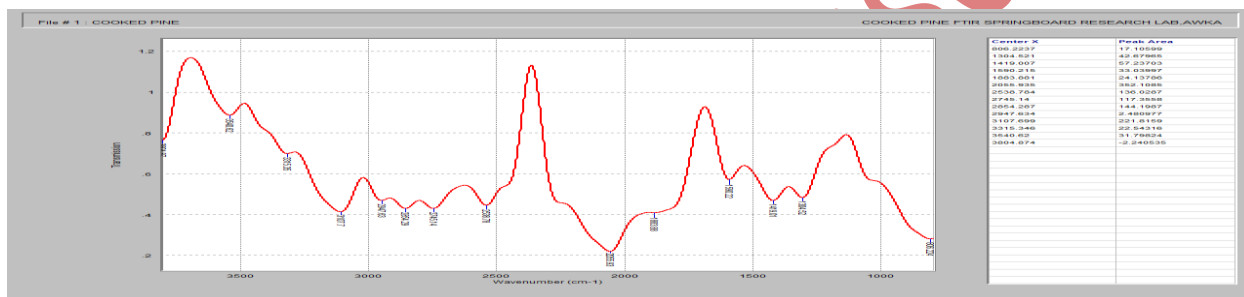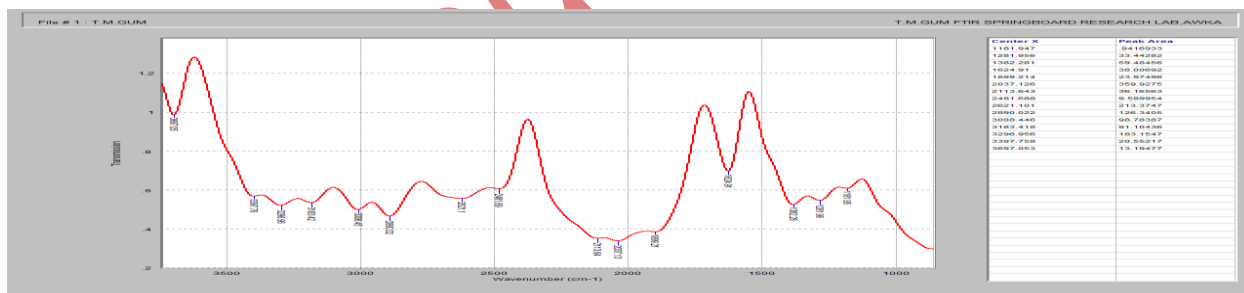

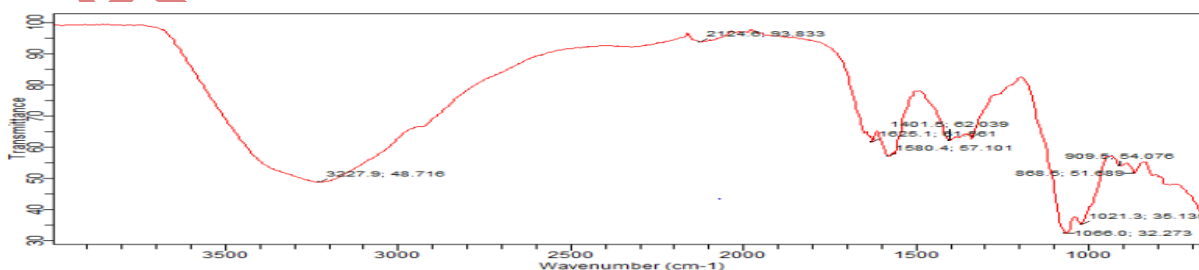**Fig 2:** FTIR Spectra for CPEG

Fig 3: FTIR Spectra for TMEG
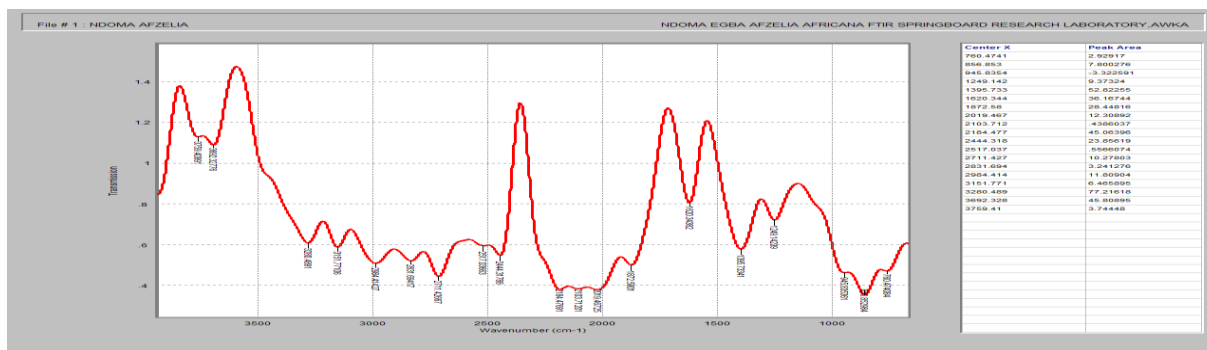

Fig 4: FTIR Spectra of XG

Fig 5: FTIR Spectra of Afzelia Africana (AA)

Aqueous Stability

Table 4 depicts the aqueous stability result of the polymer. From table 4, there was debris formation at the bottom of the solution at 29°C (ambient condition) for all polymers, but when the fluid was heated up to 85°C, a clear and compatible solution was seen. This confirmed the ability of the 3 polymers to form colloidal phase with water at elevated temperatures for effective CEOR without possibly damaging the pore channels of the formations when utilizing for flood operation.

Table 4: Aqueous Stability of Polymer

S/N	Polymer	Concentration wt%	Result@ 27°C	Result@ 85°C
1	CPEG	0.25,0.5, 1 and 2	Clear solution with debris at the bottom	Clear and Compatible solution
2	TMEG	0.25,0.5, 1 and 2	Clear solution with slight formation of particles at the bottom	Clear and Compatible solution
3	XG	0.25,0.5, 1 and 2	Cloudy yellow solution with slight particles at the base	Clear and compatible solution
4	AA	0.25,0.5, 1 and 2	Cloudy brown solution with slight formation of particles at the bottom	Clear and compatible solution

Polymer Viscosity Evaluation

Figure 6 depicts the impact of polymer concentration on viscosity. From Figure 6, there is an increase in dynamic viscosity with corresponding increase in concentration at normal temperature. XG recorded a viscosity increase from 0.9642cp to 2.7318cp with concentration increase from 0.25wt% to 2wt%, CPEG recorded viscosity increase from 0.8679cp to 1.0274cp, TMEG recorded viscosity increase from 0.8445cp to 0.9237cp, while AA recorded viscosity increase from 0.9124cp to 2.1273cp with concentration increase from 0.25wt% to 2wt% respectively. As observed from Figure 6, XG recorded the highest viscosity, followed by AA, CPEG and TMEG in reducing order of viscosity. The high viscosity of XG is attributed to its molecular structure which enables it to form increased intermolecular reaction [26]. The viscosity behavior of the AA, CPEG and TMEG can be tied to their structure comprising of un-substituted and substituted zones; with their degree of viscosity being influenced by the amount of substituted regions [27]. Based on this, we can concluded that the quantity of un-substituted regions influences rheology of the polymers with increase in polymer concentration influencing the interaction rate between large molecules. Figures 7-10 highlights the impact of temperature variation on the absolute viscosity of CPEG, XG, TMEG and AA. As shown in Figure 7, the viscosity of 0.25wt% CPEG reduced by 28.89% at 55°C temperature. The viscosity of 0.5wt% CPEG reduced by 29.81% at 55°C temperature. The viscosity of 1wt% CPEG reduced by 24.57% at 55°C temperature. The viscosity of 2wt% CPEG reduced by 15.12% at 55°C temperature. As shown in Figure 8, the viscosity of 0.25wt%

XG reduced by 22.16% at 55°C temperature. The viscosity of 0.5wt% XG reduced by 30.56% at 55°C temperature. The viscosity of 1wt% XG reduced by 38.08% at 55°C temperature. The viscosity of 2wt% XG reduced by 41.33% at 55°C temperature. As shown in Figure 9, the viscosity of 0.25wt% TMEG reduced by 32.66% at 55°C temperature. The viscosity of 0.5wt% TMEG reduced by 33.66% at 55°C temperature. The viscosity of 1wt% TMEG reduced by 30.22% at 55°C temperature. The viscosity of 2wt% XG reduced by 26.43% at 55°C temperature. As shown in Figure 9, the viscosity of 0.25wt% AA reduced by 15.6% at 55°C temperature. The viscosity of 0.5wt% AA reduced by 30.95% at 55°C temperature. The viscosity of 1wt% TMEG reduced by 29.62% at 55°C temperature. The viscosity of 2wt% XG reduced by 30.51% at 55°C temperature. The reduction in viscosity of polymer is due to increase in kinetic or thermal energy of the molecules, and increase in polymer hydrolysis and is in-line with Khan et al, [28] study. Comparing Figures 7-10, XG recorded the highest percentage viscosity loss due to increase in temperature while TMEG recorded the least percentage viscosity loss. Figure 11-14 depicts the impact of salinity variation on the absolute viscosity of CPEG, XG, TMEG and AA. As shown in Figure 11, 0.25wt% CPEG recorded 4.81%, 5.39% and 6.64% increase in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. 0.5wt% CPEG recorded 3.77%, 3.86% and 6.6% increase in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. 1wt% CPEG recorded 3.78%, 6.19% and 10.41% increase in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. 2wt% CPEG recorded 5.68%, 8.1% and 9.08% increase in viscosity at 10000ppm, 20000ppm and 30000ppm salinities respectively. The viscosity increase of the polymer can be tied to its increasing intermolecular reaction at elevated concentration [29]. As shown in Figure 12, 0.25wt% XG recorded 2.17%, 1.45% and 0.42% drop at salinity of 10000ppm, 20000ppm and 30000ppm. The viscosity of 0.5wt% XG reduced by 8.95%, 7.49% and 5.37% at salinity of 10000ppm, 20000ppm and 30000ppm. These reduction is due to the screening of the polymer chains; thus agreeing with [30] study which reports that XG conformation collapses as a result of charge screening.1wt% XG recorded 8.74%, 11.32% and 14.79% increase in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. The viscosity of 2wt% XG increased by 3.99%, 6.36% and 6.64% at 10000ppm, 20000ppm and 30000ppm salinities respectively. This is due to increase in ionic strength of the solution as a result of salt addition. As shown in Figure 13, 0.25wt% TMEG recorded 7.03%, 7.21% and 8.22% increase in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. 0.5wt% TMEG recorded 4.84%, 5.91% and 7.01% increase in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. 1wt% TMEG recorded 2.39%, 3.7% and 5.72% increase in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. 2wt% TMEG recorded 0.45%, 1.14% and 2.62% increase in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. The less sensitivity of TMEG is in-line with Ezeh et al [31] study which showed that some polymer exhibits less sensitivity to salinity. As shown in Figure 14, 0.25wt% AA recorded 2.03%, 3.67% and 5.10% increase in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. 0.5wt% AA recorded 2.37%, 0.65% and 0.79% drop in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. 1wt% AA recorded 4.47%, 2.82% and 1.35% drop in viscosity at salinity of 10000ppm, 20000ppm and 30000ppm respectively. 2wt% AA recorded viscosity drop of 1.8% and viscosity rise of 1.14% and 2.62% at salinity of 10000ppm, 20000ppm and 30000ppm respectively.
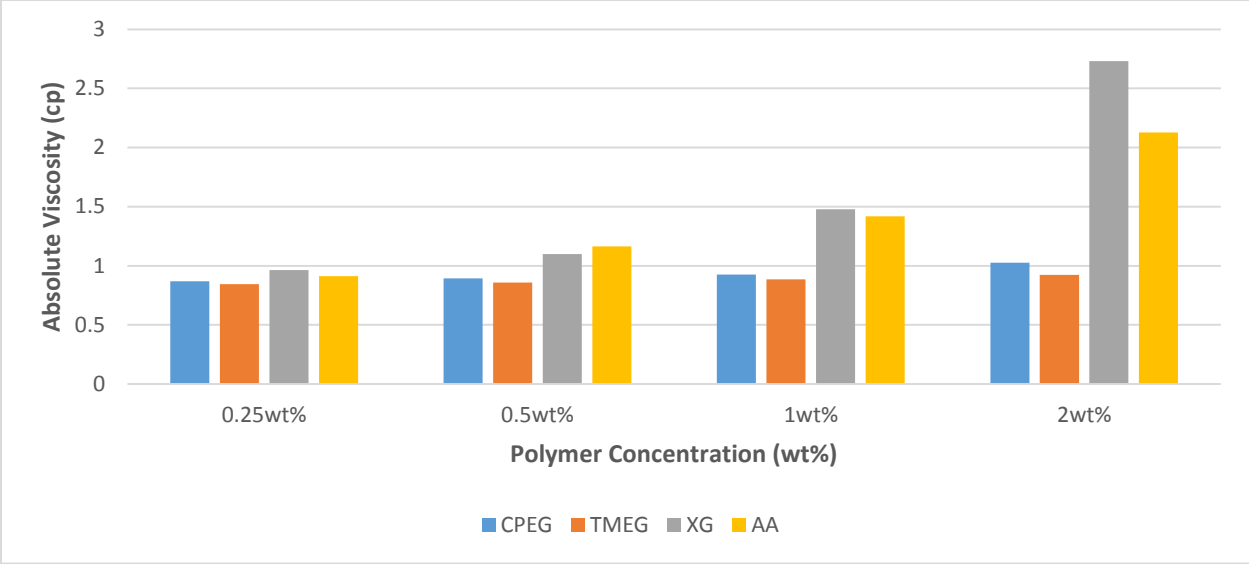
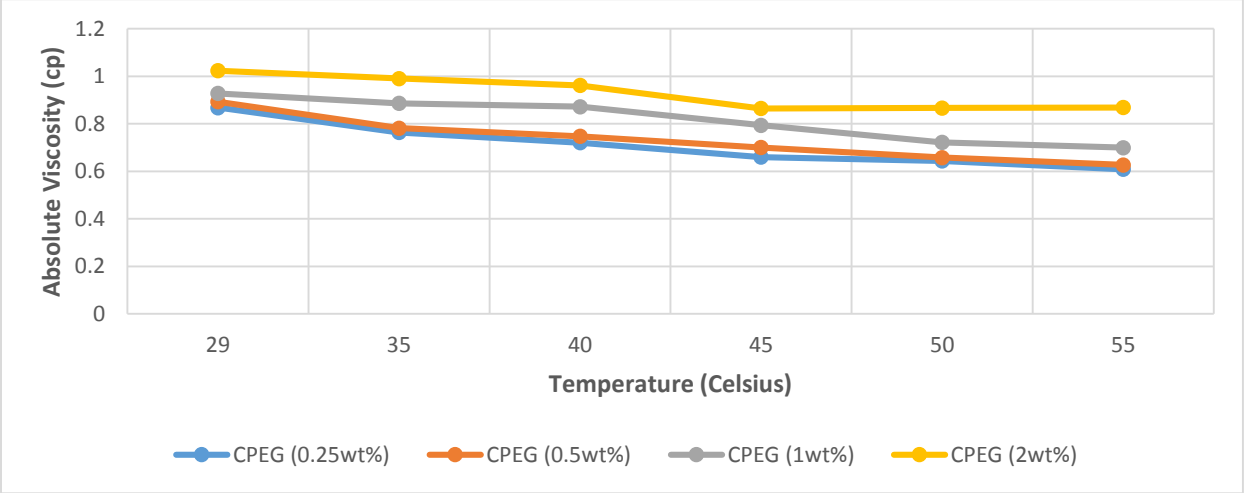**Fig 6:** Impact of Polymer Concentration on Absolute Viscosity

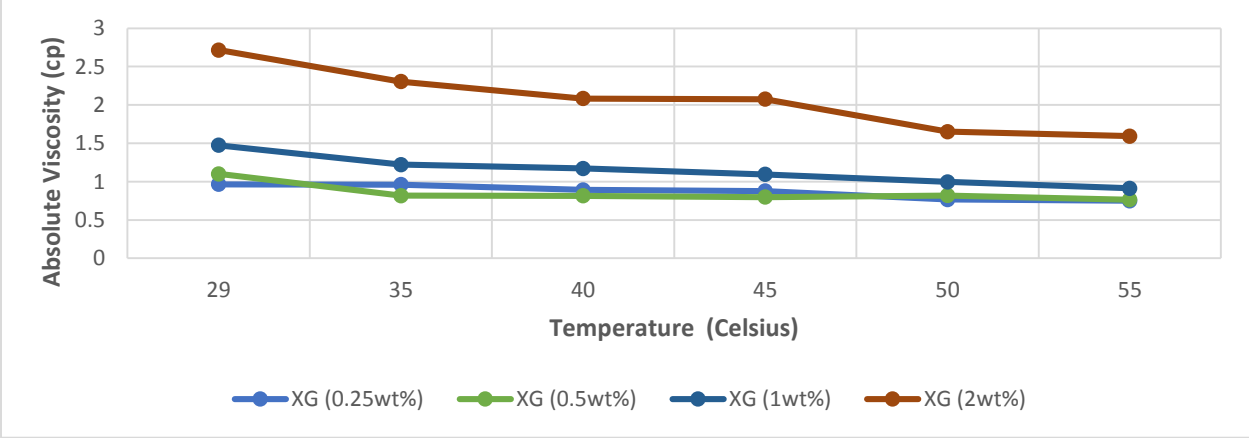**Fig 7:** Impact of Temperature Variation on the Absolute Viscosity of CPEG

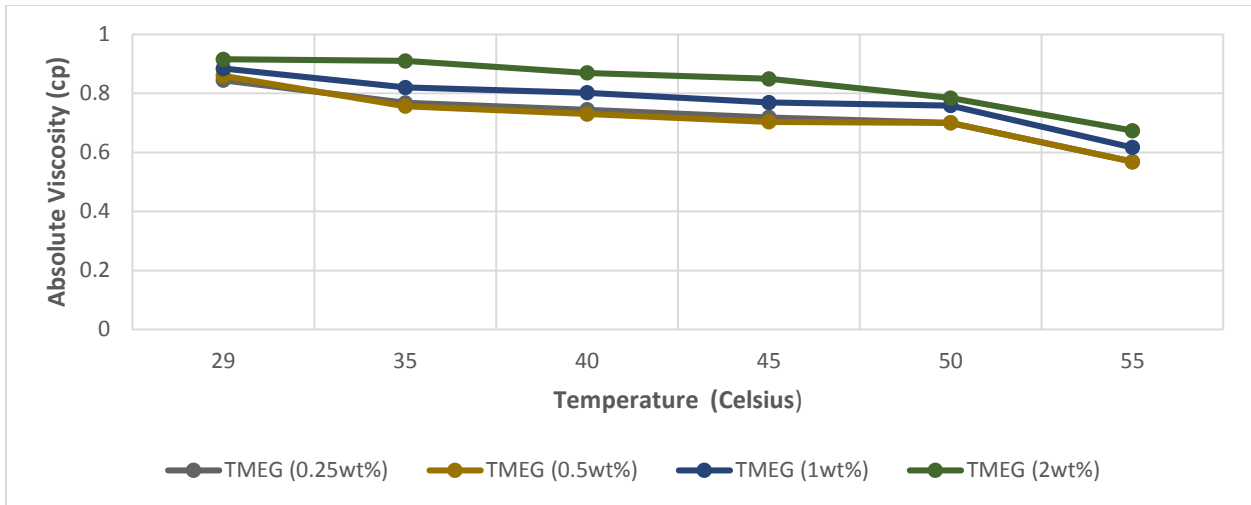**Fig 8:** Impact of Temperature Variation on the Absolute Viscosity of XG

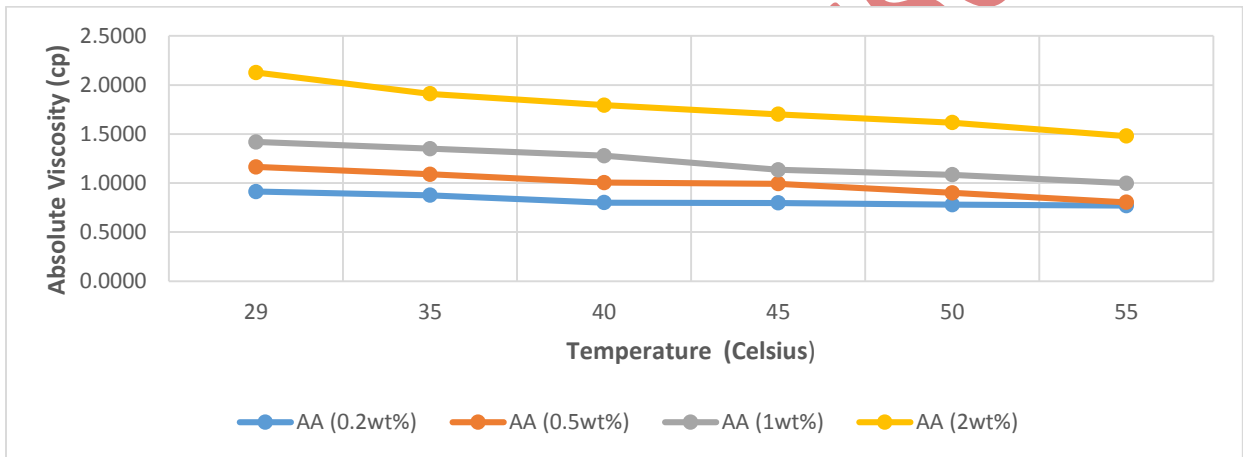**Fig 9:** Impact of Temperature Variation on the Viscosity of TMEG

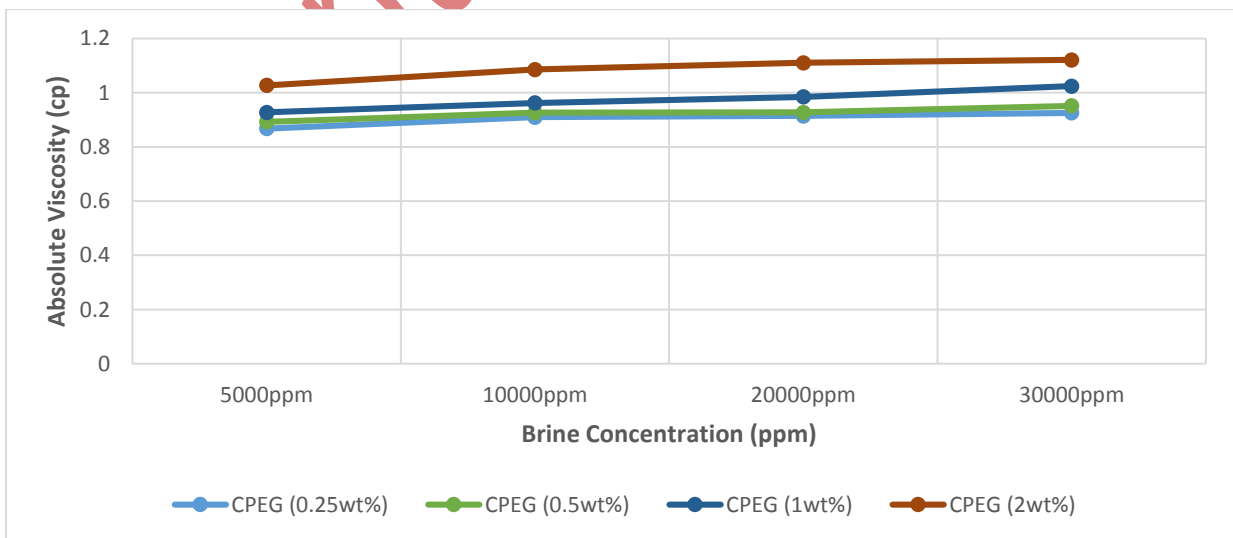**Fig 10:** Impact of Temperature Variation on the Viscosity of AA

Fig 11: Impact of Salinity Variation on the Viscosity of CPEG
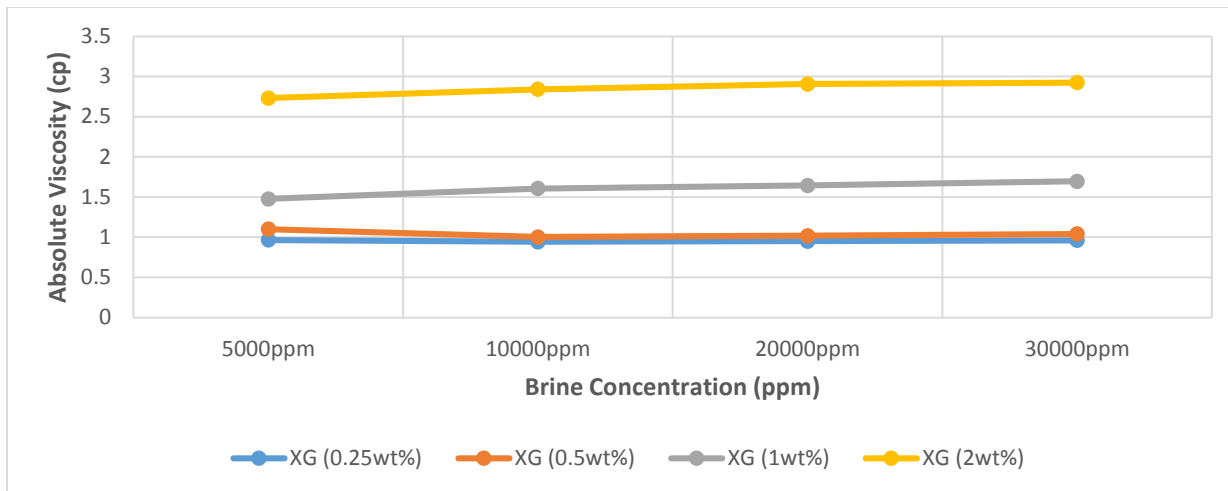
Fig 12: Impact of Salinity Variation on the Viscosity of XG
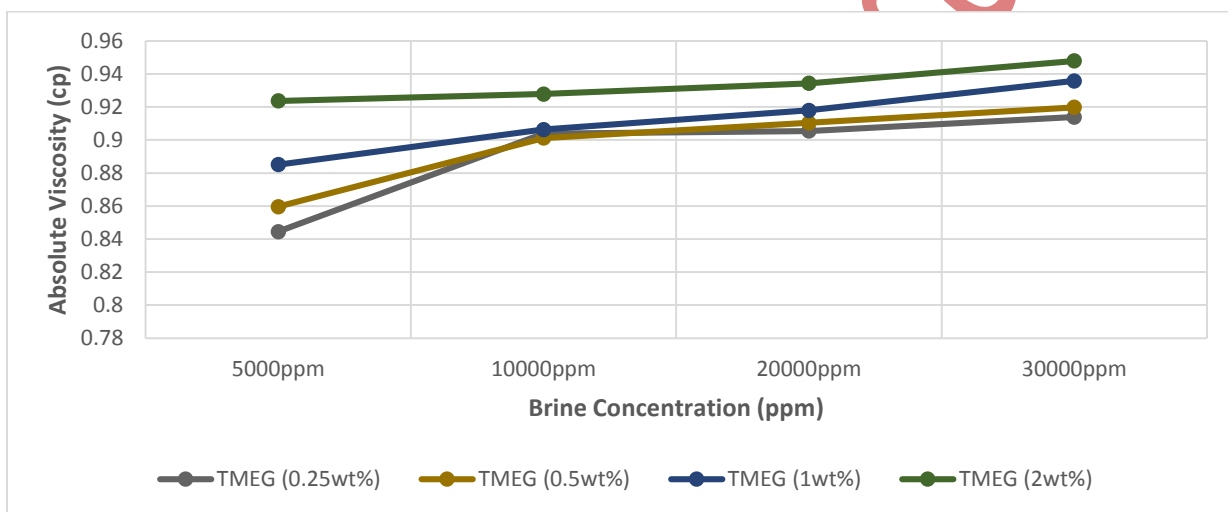

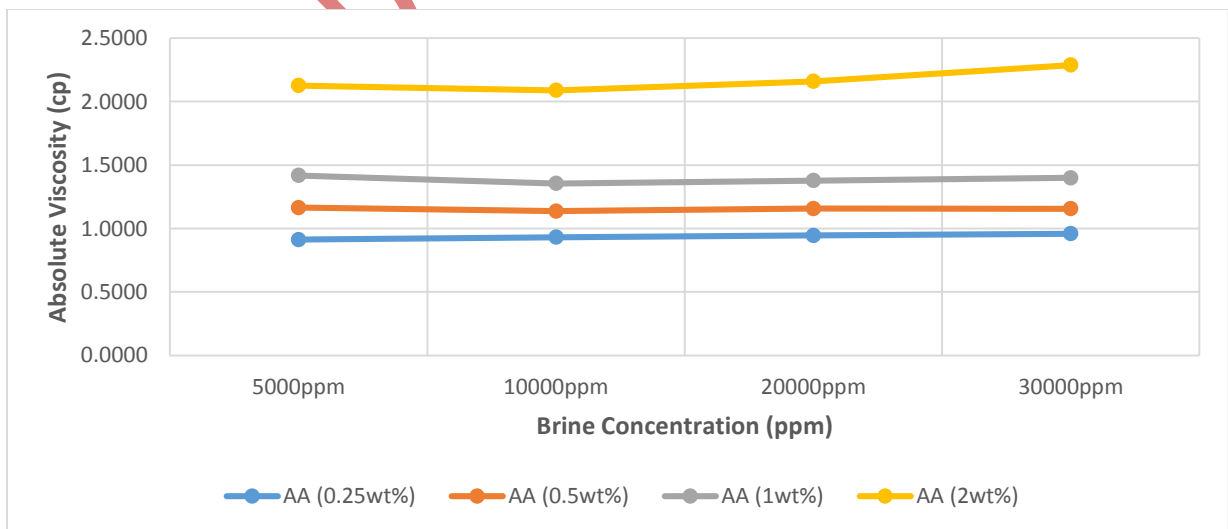**Fig 13:** Impact of Salinity Variation on the Viscosity of TMEG

Fig 14: Impact of Salinity Variation on the Viscosity of AA.

Polymer Adsorption

Figure 15 depicts the absorbance of CPEG, TMEG, XG and AA at various concentration before and after adsorption test. As shown in Figure 15, CPEG absorbance reduced by 34.03%, 60.82%, 61.75% and 64.03% for 0.25wt%, 0.5wt%, 1wt% and 2wt% respectively. TMEG absorbance reduced by 4.82%, 14.95%, 39.29% and 63.54% for 0.25wt%, 0.5wt%, 1wt% and 2wt% respectively. XG absorbance reduced by 20.34%, 13.88%, 26.75% and 21.59% for 0.25wt%, 0.5wt%, 1wt% and 2wt% respectively. AA absorbance reduced by 27%, 14.46%, 16.7% and 20.28% for 0.25wt%, 0.5wt%, 1wt% and 2wt% respectively. It's observed that CPEG and TMEG's adsorption rate increased with increase in concentration, while AA and XG's absorbance reduced with concentration increase from 0.25wt% to 0.5wt% before increasing with increase in concentration. The higher adsorption rate of CPEG, TMEG, XG and AA at higher concentration is due to the increased number of polymer molecules which increases the likelihood of interaction between polymer molecule and sand surface, and is in-line with Mishra et al [32] study.
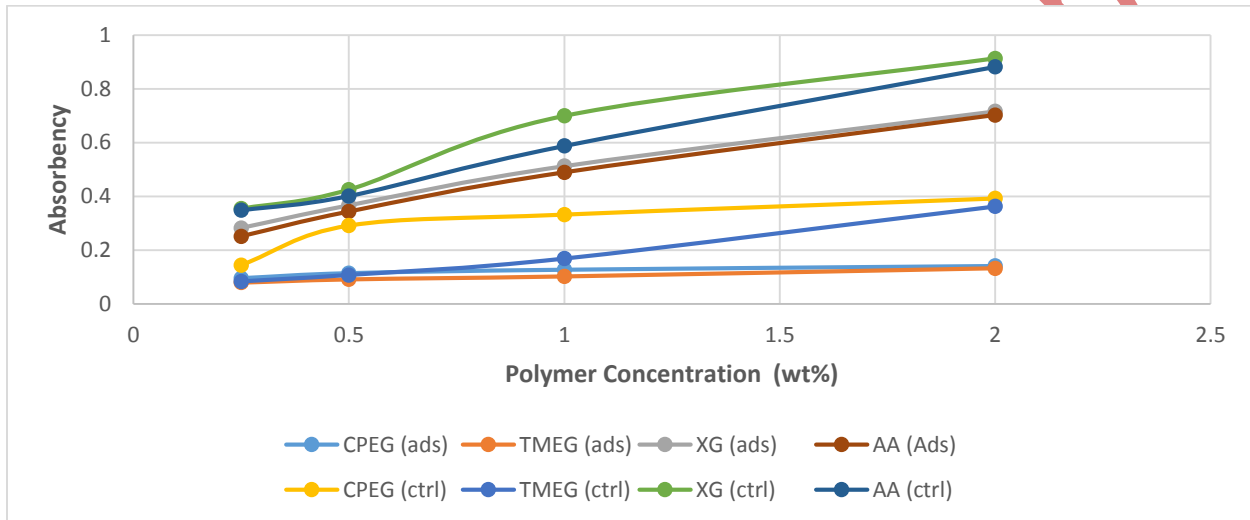

Figure 15: Absorbance of Polymer before and after Adsorption test

Core Flooding

Figures 16 highlights the additional recovery of CPEG, TMEG, XG and AA at various concentration. As shown in Figure 16, CPEG recorded 17.65%, 16.67%, 10% and 11.90% additional oil recovery at 0.25wt%, 0.5wt%, 1wt% and 2wt% respectively. TMEG recorded 16.67%, 11.36%, 12.50% and 10% additional oil recovery at 0.25wt%, 0.5wt%, 1wt% and 2wt% respectively. XG recorded 15%, 13.64%, 14.29% and 9.09% additional oil recovery at 0.25wt%, 0.5wt%, 1wt% and 2wt% respectively. AA recorded 14.5%, 13.72%, 13.1% and 8% additional recovery at 0.25wt%, 0.5wt%, 1wt% and 2wt% respectively. As observed from Figure 16, CPEG performed better than TMEG and XG, and this can be attributed to the ability of the polymer solution yield favorable mobility ratio, reduce relative water permeability and effective sweep crude oil out of the formation. Comparing Figure 16 with Figure 15, the EOR performance of the CPEG, TMEG and XG reduced with increase in concentration and increase viscosity. This is attributed to polymer retention behavior which leads to bank formation and restricted flow of further polymers, and is in-line with Ojukwu et al [33] report.
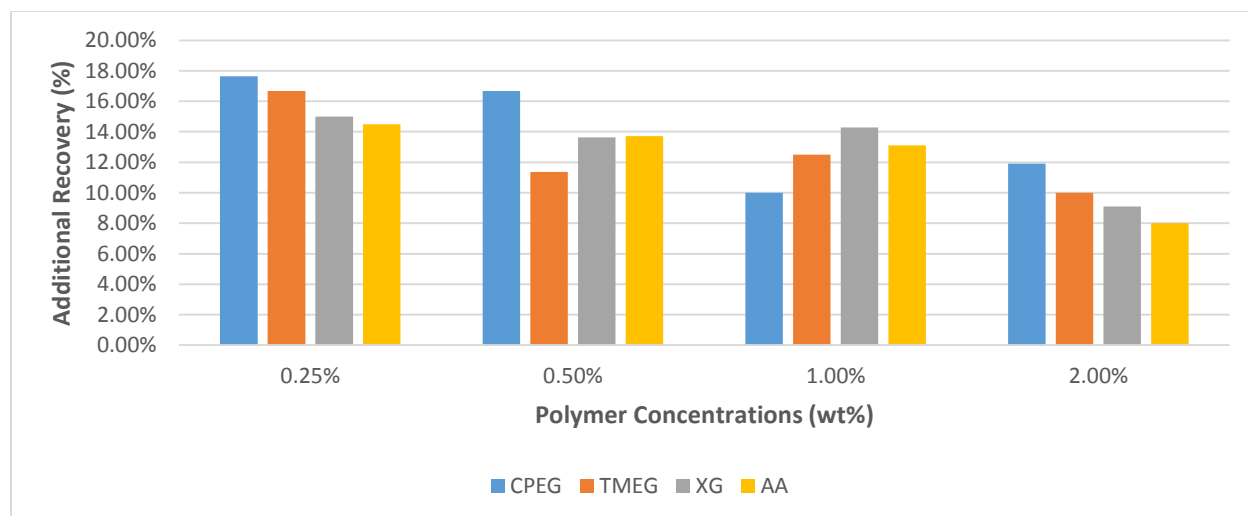
Fig 16: Additional Recovery of Various Concentration of Polymers

CONCLUSION

From the study conducted, the following conclusion are made

- CPEG, AA TMEG and XG are all polysaccharides
- XG, CPEG, AA and TMEG are compatible in soft brine and can be used in CEOR.
- At all concentrations, XG recorded the highest viscosity in solution.
- Salinity impacts on the viscosity of polymers.
- Adsorption rate of polymers increases with increase in their concentration.
- The biopolymers utilized for CEOR recorded their favorable mobility ratio at 0.25wt% concentration
- 0.25wt% CPEG performed best of all the polymer formulations used for the study as it yielded additional 17.65% while 0.25wt% TME. 0.25wt% XG and 0.25wt% AA recorded 16.67%, 15% and 14.50% additional recoveries respectively.

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