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An Investigation on the Enhanced Oil Recovery Performance of Local Biopolymers

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ABSTRACT

The introduction of polymers into the reservoir yields a 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 potential of local bio-polymers in alternating conventional polymers in CEOR. This has 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 polymers, while xanthan gum (XG) was used as a conventional polymer. FTIR evaluation, aqueous stability, Viscosity, adsorption, and EOR core-flood study were conducted in the investigation. From the FTIR evaluation CPEG, AA, and TMEG can be classified as polysaccharides. From the aqueous stability test, CPEG, AA, and TMEG formed a colloidal phase with water. From the viscosity result CPEG, AA, and TMEG recorded similar viscosity trends present in XG. From the adsorption test, an increase in concentration increased the adsorption rate. From the CEOR study, a 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 an furthur 17.65% after secondary recovery, while TMEG, XG, and AA recorded an additional 16.67% 15%, and 14.5% respectively. The study showed that CPEG, AA, and TMEG can be used as alternatives to XG.

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Introduction

There is usually high residual oil saturation (ROS) in the rock formation after the natural and secondary recovery phase [1], and this ROS becomes a subject of interest for the enhanced-oil-recovery (EOR) process. EOR techniques are introduced into the reservoir to produce residual and entrapped oil [2, 3]. The EOR techniques can be grouped into non-thermal and thermal EOR. Thermal EOR is not recommended for reservoirs with deeper depths, underlying aquifers, or thin pay zones. This results from heat loss to overburden and under-burden layers [4]. The environmental impact concern posed by greenhouse gases is also another determinant [5] and this has resulted in the preference for EOR techniques that do not require heat. Chemical-enhanced oil recovery (CEOR), a non-thermal technique, has shown promising signs of improving oil recovery due to its efficiency and ease of utilization. Several reagents such as surfactants, polymers, nanoparticles, and alkalis 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 has 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 the 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 the early breakthrough of water. To prevent this, polymer reagents are introduced during EOR to improve the viscosity of the displacing fluid to achieve a favorable mobility ratio [10]. These polymers could be natural or synthetic based, and exhibit pseudo-plastic fluid behavior, with a shear-thinning viscosity [11]. Several polymer reagents have been utilized for CEOR, but xanthan gum (biopolymer) and hydrolyzed polyacrylamide (HPAM) are the most used polymers [12]. PAM has significantly higher viscoelastic features than xanthan gum (XG) in freshwater, but not in saline water [13]. As a result of this, the synthetic polymer is substituted by XG which has a high tolerance for salinity, mechanical shear, and temperature [14]. Polymer CEOR is mostly suited for oil reservoirs with a viscosity below 100 cp, temperatures less than 72 °C, and low-moderate saline reservoirs [15]. Conventional polymers such as xanthan gum are globally accepted and utilized for CEOR, but not cost-friendly to developing countries due to importation costs. These have led to a search for cheaper and available local alternatives. The successful discovery of these 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. A study conducted by Abdulraheem et al. [18] 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 flagellates, 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 potential of Terminalia mantaly in replacing polyacrylamide in EOR, with the Terminalia mantaly recording 90% and 81% recoveries in soft and hard brine, respectively. However, the effectiveness of these local polymers at prevailing conditions of salinity and temperature needs to be comprehensively evaluated to confirm their ability to replace conventional or foreign polymer chemicals. In this study, Terminalia mantaly exudate (TMEG), afzelia africana (AA), and cook pine exudate (CPEG) were utilized as local polymer, while xanthan gum (XG) was utilized as a 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 in Madagascar. Afzelia africana plant grows in south-eastern Nigeria, east & west coasts of Africa, in dense dry forests, wooded savannah, and semi-deciduous forest areas. Cook pine plant grows in Nigeria, with its origin in Australia.

Experiment

Materials

The materials utilized for the experimental analysis include 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 ^{o}API and viscosity of 3.753 cp at 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.’s method [24]. The polymer was recovered from the incised portion of a tree and dried in a lab for 48 hours at 40 °C. 100 g of the dried polymer was cleansed with deionized water to eliminate foreign particles. The washed exudate gum was hydrated in a chloroform/water mixture for 48 hours to soften. The hydrated polymer was sieved to remove unwanted materials before drying in the oven for 72 hours at 40 °C. The dried gum was pulverized into smaller particles and sieved to obtain uniform particles before storing them in an airtight container. CPEG was extracted from the incised section of the parent tree and solubilized in water for 24 hours. Unwanted materials were removed from the solution before being dried for 72 hours at 40 °C, using a lab oven. The dried polymer was pulverized and sieved into finer and uniform particles before being stored in an airtight container. AA pods were heated for 5 minutes at 45 °C, before being broken down to recover the seeds. The recovered seeds were pulverized and sieved to recover uniform-sized particles.

FTIR Characterization

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

Aqueous Stability Test

To conduct a fluid-fluid interaction study, a phase stability experiment on the polymer chemicals and brine solution was 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 concentrations depicted in Table 1 were introduced into 400 ml of soft brine (5000 ppm) solution. The result polymer solution was introduced to 4 test tubes labeled 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 ℃.

Table 1. Polymer concentration

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

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 the 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. Tables 2 & 3 depict 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%, 2wt%	5000 ppm, 10000 ppm, 20000 ppm, 30000 ppm
2	CPEG	0.25wt%, 0.5wt%, 1wt%, 2wt%	5000 ppm, 10000 ppm, 20000 ppm, 30000 ppm
3	XG	0.25wt%, 0.5wt%, 1wt%, 2wt%	5000 ppm, 10000 ppm, 20000 ppm, 30000 ppm
4	AA	0.25wt%, 0.5wt%, 1wt%, 2wt%	5000 ppm, 10000 ppm, 20000 ppm, 30000 ppm

Table 3. Impact of temperature variation on polymer viscosity

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

Polymer Adsorption

The ultraviolet (UV) radiation method was utilized using a Biomate UV spectrophotometer. The spectrophotometer was calibrated using its operational manual. Polymers with concentration depicted in Table 1 were agitated uniformly for 15 minutes before a 3 hours stabilization time was allowed. The solution was introduced into the UV cell to derive the absorbance of the solution. 100 ml of solution was flown through a 25 g weigh sand-pack of uniform particle size (0.589 mm 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 polymers 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 2500 psi to reach full saturation over 48 hours period. After 48 hours, the pressure of the system was relieved before reweighing the saturated cores. The cores were placed into the core holder shown in Fig. 1 at a confining pressure of 1000 psi. At a 2 cc/s rate, brine was introduced to ensure that the trapped air bubbles were removed and ensure 100% saturation of the core. The brine was drained out continuously by 2 cc/s rate crude oil until S_{wi} (initial water saturation) was attained. The imbibition process was conducted with 2 cc/s rate brine until S_{or} (residual oil saturation) was derived during brine flooding. After the establishment of S_{or}, polymer flooding was then carried out. The core-flooding was carried out at ambient conditions of pressure and temperature with Fig. 1 showing the experimental core-flood setup.

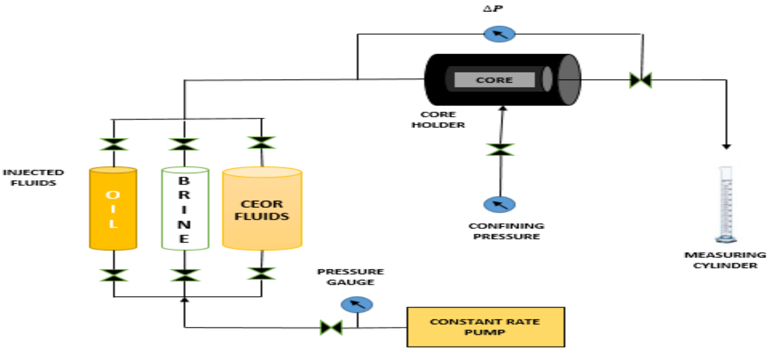


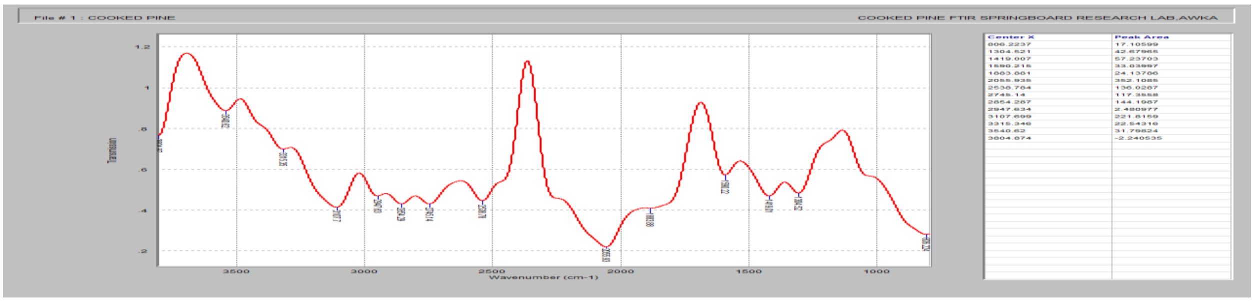
Fig. 1. EOR experimental setup

Results and Discussions

FTIR Evaluation

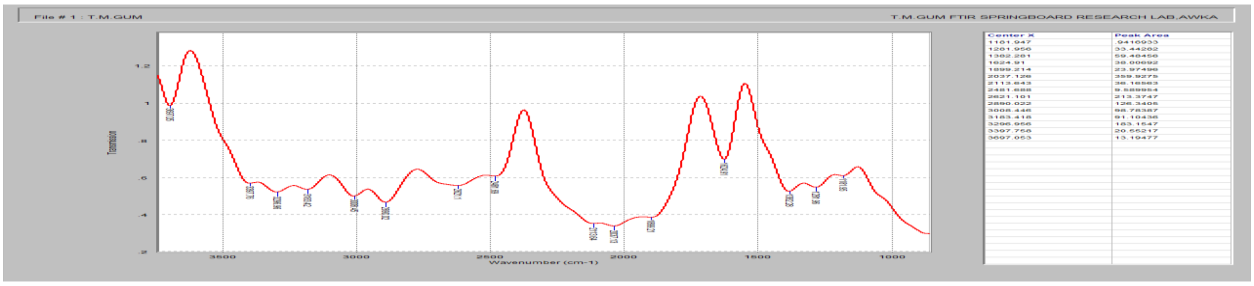
Figs 2-5 depict the FTIR Spectra of CPEG, TMEG, XG, and AA. As shown in Fig. 2, the wavelengths of 3804.874 cm^{-1}, 2854.287 cm^{-1}, 2538.784 cm^{-1}, 1883.881 cm^{-1}, 1419.007 cm^{-1} and 806.2237 cm^{-1} indicate the presence of alcohol, methylene, nitriles, carboxylic acid, ester, ethene, and chloro compounds. As shown in Fig. 3, the wavelengths of 3697.053 cm^{-1}, 2890.022 cm^{-1}, 2481.688 cm^{-1}, 2037.26 cm^{-1}, 1899.214 cm^{-1}, 1624.910 cm^{-1}, 1382.281 cm^{-1} and 1181.947 cm^{-1} indicate the presence of alcohol, methylene, nitriles, carboxylic acid, ester, amine, ethene and ether compounds. As shown in Fig. 4, the wavelengths of 3227.9 cm^{-1}, 2124.6 cm^{-1}, 1625.1 cm^{-1}, 1580.4 cm^{-1}, 1401.5 cm^{-1}, 1021.3 cm^{-1}, and 868.5 cm^{-1} indicate the presence of alcohol, methylene, ester, ketones, carboxylic acid, acetate and glycoside compounds. As shown in Fig. 5, the wavelengths of 3692.33 cm^{-1}, 2711.43 cm^{-1}, 2517.04 cm^{-1}, 1872.581 cm^{-1}, 1395.73 cm^{-1}

and 856.853 cm^{-1} indicate 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 (1160 cm^{-1}), carboxyl (1529 cm^{-1}), carbonyl (1627 cm^{-1}) and hydroxyl groups (3386 cm^{-1}). Some of these functionalities are present in the CPEG, AA, and TMEG and this shows that they are polysaccharides.



Center X	Peak Area
806.2237	17.10599
1304.821	42.67865
1419.007	57.23703
1580.216	33.03887
1663.661	24.13786
2055.835	352.1085
2536.764	136.0267
2745.14	117.3558
2854.287	144.1967
2947.634	2.480977
3107.699	221.6159
3315.346	22.54316
3540.62	31.79824
3804.674	-2.240535

Fig. 2. FTIR spectra for CPEG



Center X	Peak Area
1161.947	.9416933
1261.956	33.44262
1362.261	59.48456
1624.91	38.00692
1899.214	23.97496
2037.128	359.9275
2113.643	36.16563
2481.688	9.589954
2821.101	213.3747
2880.022	126.3405
3008.446	88.78387
3183.418	91.10436
3296.956	183.1547
3397.758	20.55217
3697.053	13.19477

Fig. 3. FTIR spectra for TMEG

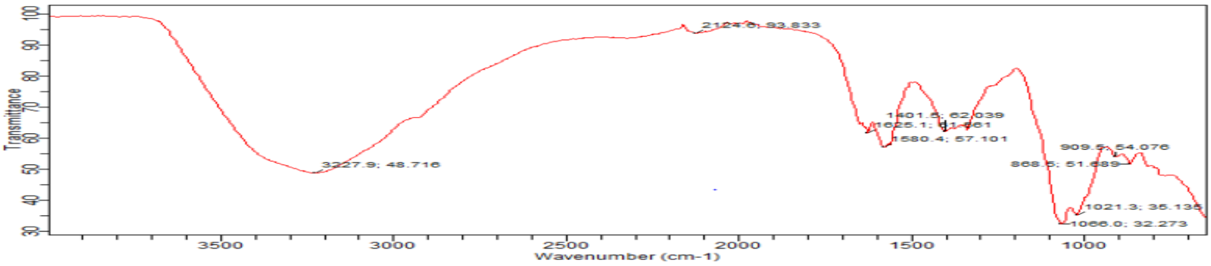
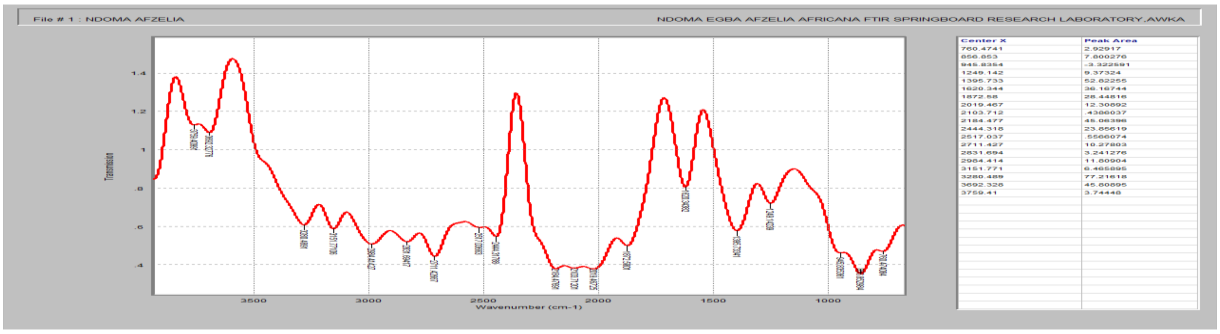


Fig. 4. FTIR spectra of XG



Center X	Peak Area
760.4741	2.92917
856.853	7.600276
945.8354	-3.322591
1249.142	9.37324
1395.733	52.62255
1620.344	36.16744
1872.58	28.44816
2019.467	12.30892
2103.712	.4386037
2184.477	45.06398
2444.318	23.65619
2517.037	.5566074
2711.427	10.27803
2831.694	3.241276
2984.414	11.60904
3151.771	6.465895
3280.489	77.21618
3692.328	45.60895
3759.41	3.74448

Fig. 5. FTIR spectra of 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 a colloidal phase with water at elevated temperatures for effective CEOR without possibly damaging the pore channels of the formations when utilized for flood operation.

Table 4. Aqueous stability of polymer

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

Polymer Viscosity Evaluation

Fig. 6 depicts the impact of polymer concentration on viscosity. From Fig. 6, there is an increase in dynamic viscosity with a corresponding increase in concentration at normal temperature. XG recorded a viscosity increase from 0.9642 cp to 2.7318 cp with a concentration increase from 0.25wt% to 2wt%. CPEG recorded a viscosity increase from 0.8679 cp to 1.0274 cp, TMEG recorded viscosity increase from 0.8445 cp to 0.9237 cp, while AA recorded viscosity increase from 0.9124 cp to 2.1273 cp, with concentration increase from 0.25wt% to 2wt%, respectively. As observed in Fig. 6, XG recorded the highest viscosity, followed by AA, CPEG, and TMEG in reducing order. The high viscosity of XG is attributed to its molecular structure which enables it to form increased intermolecular reactions [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 conclude that the quantity of un-substituted regions influences the rheology of the polymers with an increase in polymer concentration influencing the interaction rate between large molecules. Figs. 7-10 highlight the impact of temperature variation on the absolute viscosity of CPEG, XG, TMEG, and AA. As shown in Fig. 7, the viscosity of 0.25wt% CPEG reduced by 28.89% at 55 ℃. The viscosity of 0.5wt% CPEG reduced by 29.81% at 55 ℃. The viscosity of 1wt% CPEG reduced by 24.57% at 55 ℃. The viscosity of 2wt% CPEG was reduced by 15.12% at 55 ℃. As shown in Fig. 8, the viscosity of 0.25wt% XG reduced by 22.16% at 55 ℃. The viscosity of 0.5wt% XG reduced by 30.56% at 55 ℃. The viscosity of 1wt% XG reduced by 38.08% at 55 ℃. The viscosity of 2wt% XG reduced by 41.33% at 55 ℃. As shown in Fig. 9, the viscosity of 0.25wt% TMEG reduced by 32.66% at 55 ℃. The viscosity of 0.5wt% TMEG reduced by 33.66% at 55 ℃. The viscosity of 1wt% TMEG reduced by 30.22% at 55 ℃. The viscosity of 2wt% XG was reduced by 26.43% at 55 ℃. As shown in Fig. 9, the viscosity of 0.25wt% AA was reduced by 15.6% at 55 ℃. The viscosity of 0.5wt% AA was reduced by 30.95% at 55 ℃. The viscosity of 1wt% TMEG was reduced by 29.62% at 55 ℃. The viscosity of 2wt% XG was reduced by 30.51% at 55 ℃. The reduction in viscosity of the polymer is due to an increase in the kinetic or thermal energy of the molecules, and an increase in polymer hydrolysis, which is in-line with Khan et al.'s study [28]. Comparing Figs. 7-10, XG recorded the highest percentage viscosity loss due to increase in temperature while TMEG recorded the least percentage viscosity loss. Figs. 11-14 depict the impact of salinity variation on the absolute viscosity of CPEG, XG, TMEG and AA. As shown in Fig. 11, 0.25wt% CPEG recorded 4.81%, 5.39% and 6.64% increase in viscosity at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. 0.5wt% CPEG recorded 3.77%, 3.86% and 6.6% increase in viscosity at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. 1wt% CPEG recorded 3.78%, 6.19% and 10.41% increase in viscosity at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. 2wt% CPEG recorded 5.68%, 8.1%

and 9.08% increase in viscosity at salinities of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. The viscosity increase of the polymer can be tied to its increasing intermolecular reaction at elevated concentration [29]. As shown in Fig. 12, 0.25wt% XG recorded 2.17%, 1.45% and 0.42% drop at salinity of 10000 ppm, 20000 ppm, and 30000 ppm. The viscosity of 0.5wt% XG reduced by 8.95%, 7.49% and 5.37% at salinity of 10000 ppm, 20000 ppm, and 30000 ppm. This reduction is due to the screening of the polymer chains, thus in agreement with Rellegadla et al.'s study [30], 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 10000 ppm, 20000 ppm, and 30000 ppm, respectively. The viscosity of 2wt% XG increased by 3.99%, 6.36% and 6.64% at 10000 ppm, 20000 ppm, and 30000 ppm salinities respectively. This is due to increase in ionic strength of the solution as a result of salt addition. As shown in Fig. 13, 0.25wt% TMEG recorded 7.03%, 7.21% and 8.22% increase in viscosity at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. 0.5wt% TMEG recorded 4.84%, 5.91% and 7.01% increase in viscosity at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. 1wt% TMEG recorded 2.39%, 3.7% and 5.72% increase in viscosity at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. 2wt% TMEG recorded 0.45%, 1.14% and 2.62% increase in viscosity at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. The less sensitivity of TMEG is in-line with Ezeh et al.'s study [31], which showed that some polymers exhibit less sensitivity to salinity. As shown in Fig. 14, 0.25wt% AA recorded 2.03%, 3.67% and 5.10% increase in viscosity at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. 0.5wt% AA recorded 2.37%, 0.65% and 0.79% drop in viscosity at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. 1wt% AA recorded 4.47%, 2.82% and 1.35% drop in viscosity at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively. 2wt% AA recorded viscosity drop of 1.8% and viscosity rise of 1.14% and 2.62% at salinity of 10000 ppm, 20000 ppm, and 30000 ppm, respectively.

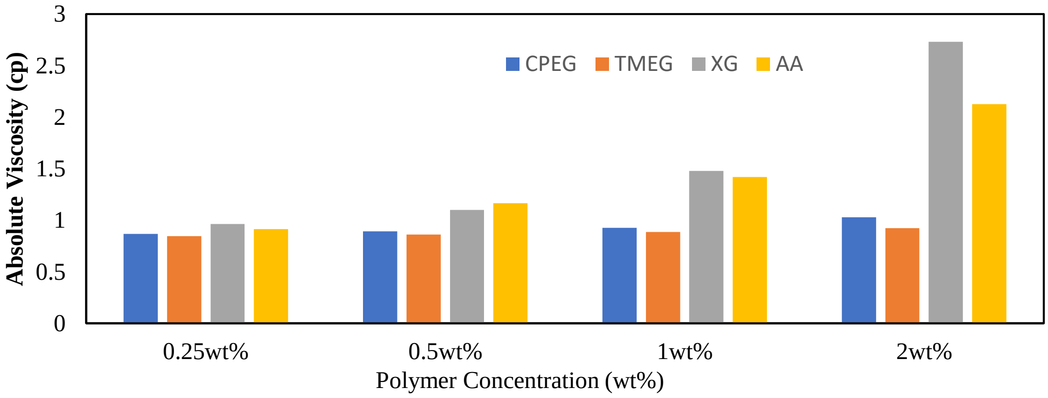


Fig. 6. Impact of polymer concentration on absolute viscosity

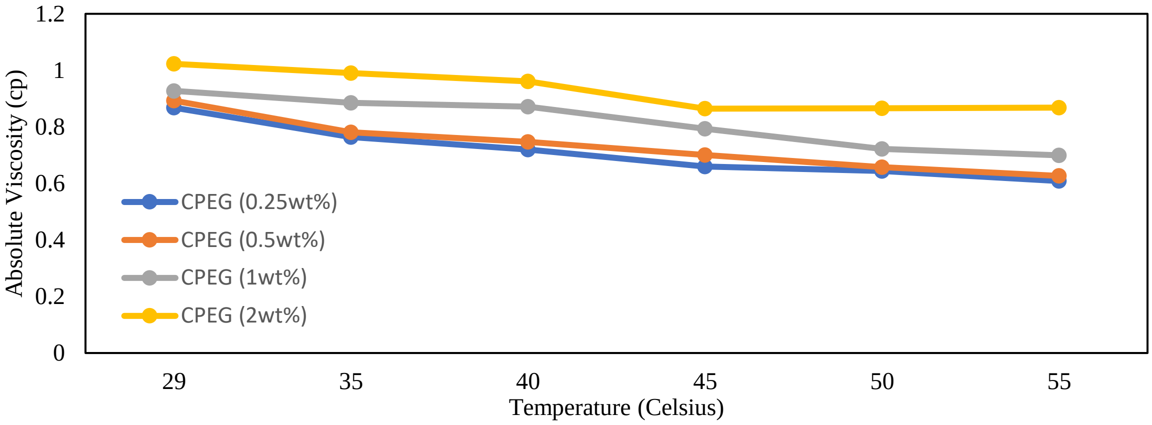


Fig. 7. Impact of temperature variation on the absolute viscosity of CPEG

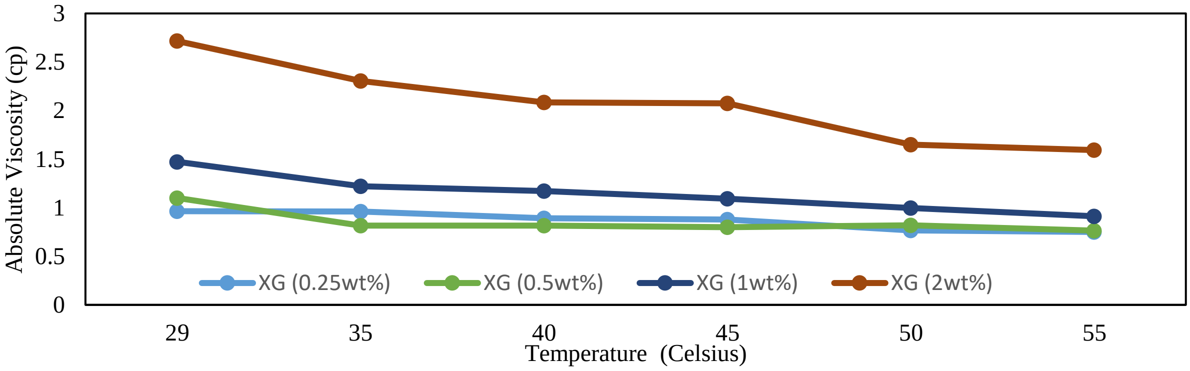


Fig. 8. Impact of temperature variation on the absolute viscosity of XG

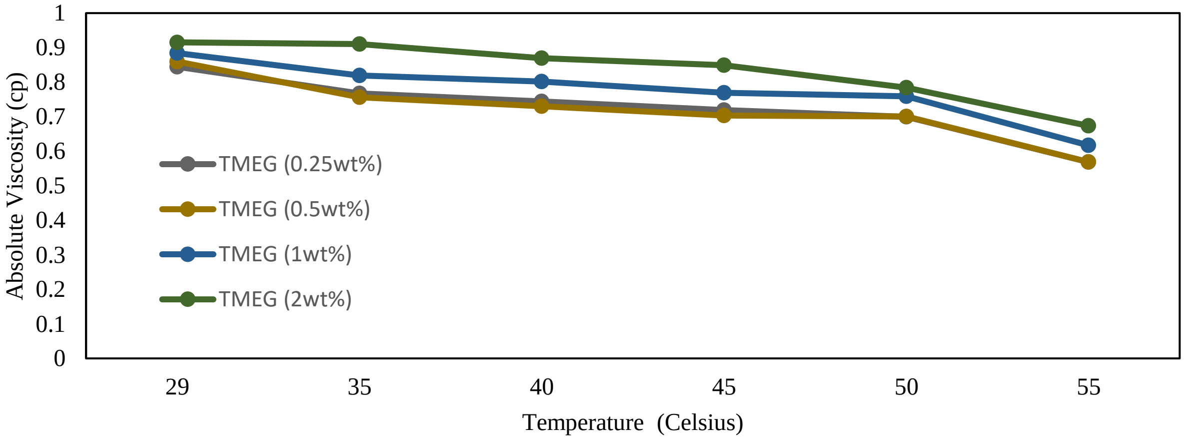


Fig. 9. Impact of temperature variation on the viscosity of TMEG

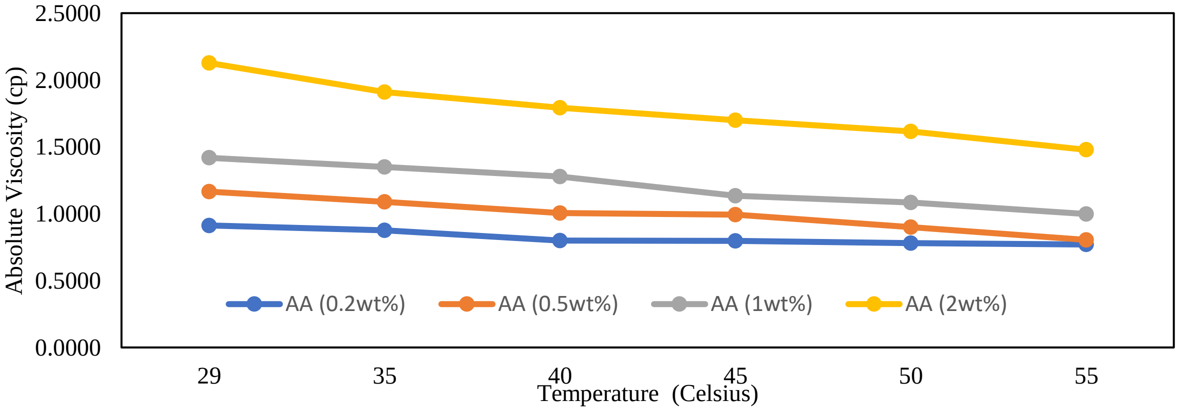


Fig. 10. Impact of temperature variation on the viscosity of AA

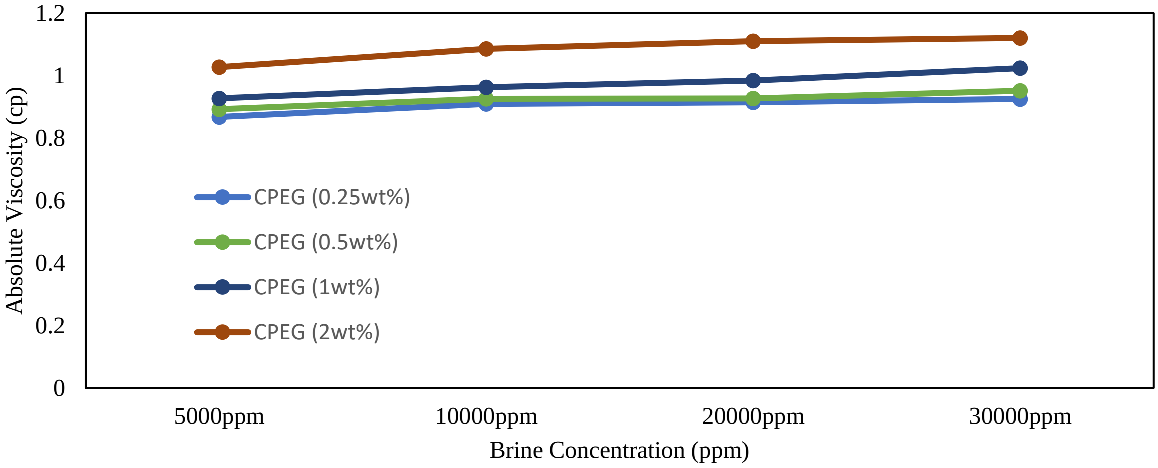


Fig. 11. Impact of salinity variation on the viscosity of CPEG

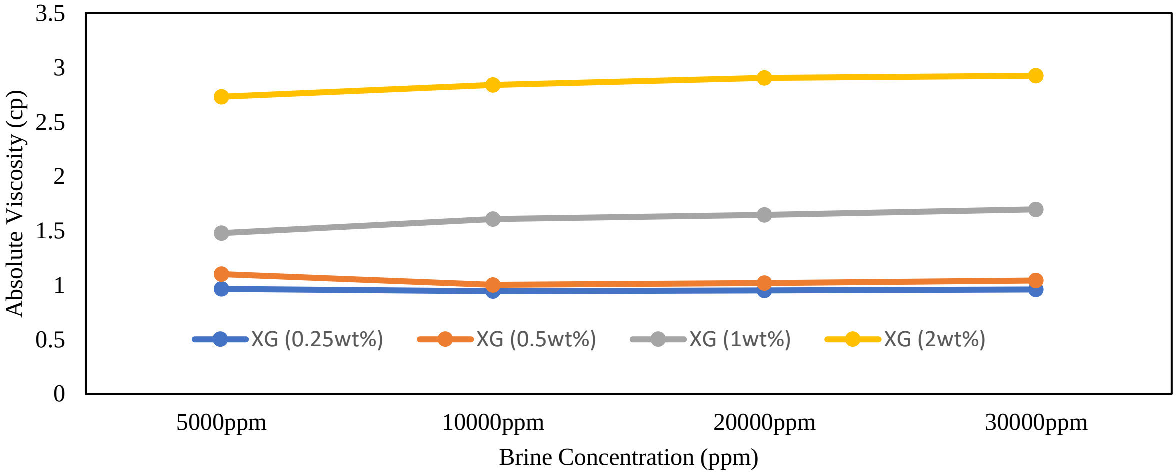


Fig. 12. Impact of salinity variation on the viscosity of XG

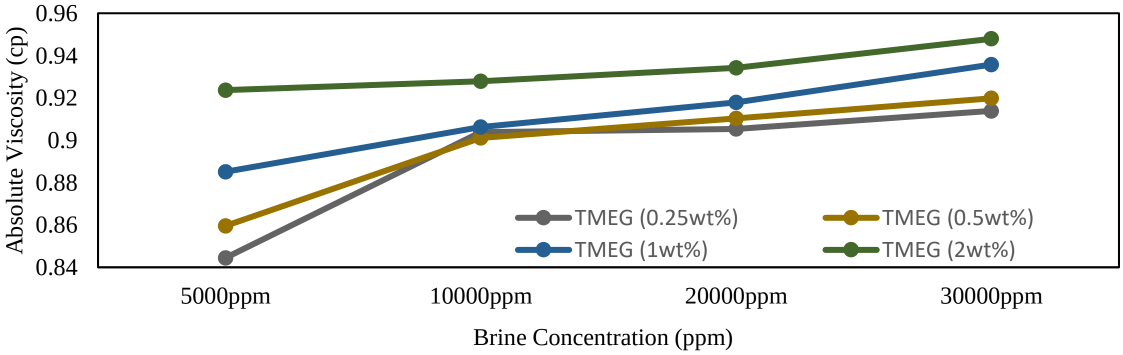


Fig. 13. Impact of salinity variation on the viscosity of TMEG

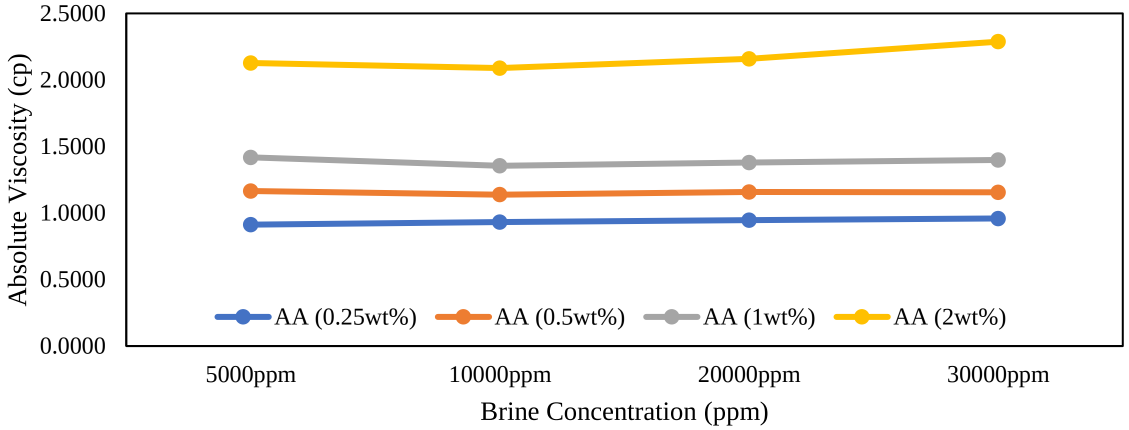


Fig. 14. Impact of salinity variation on the viscosity of AA

Polymer Adsorption

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

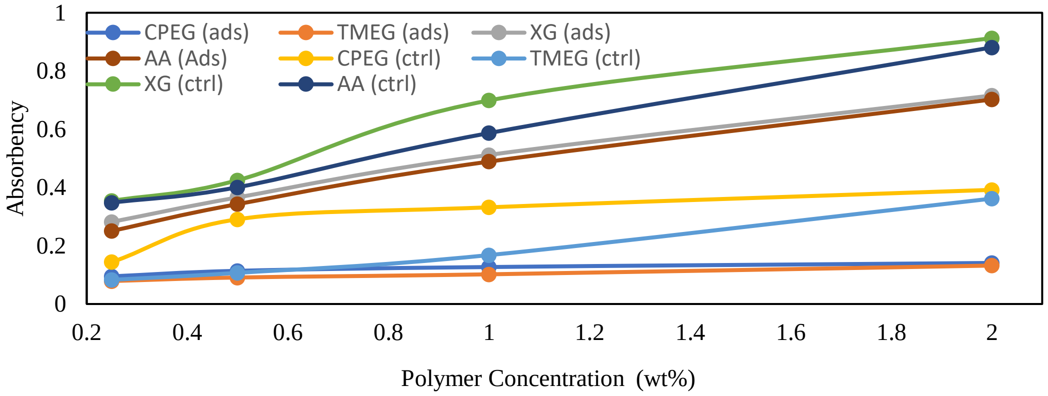


Fig. 15. Absorbance of polymer, before and after the adsorption test

Core Flooding

Fig. 16 highlights the additional recovery of CPEG, TMEG, XG, and AA at various concentrations. As shown in Fig. 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 Fig. 16, CPEG performed better than TMEG and XG. This can be attributed to the ability of the polymer solution to yield favorable mobility ratio, reduce relative water permeability, and effectively sweep crude oil out of the formation. Comparing Figs. 15 & 16, the EOR performance of the CPEG, TMEG, and XG reduced with an increase in concentration and viscosity. This is attributed to polymer retention behavior, which leads to bank formation and restricts the flow of further polymers. This is in-line with Ojukwu et al.'s report [33].

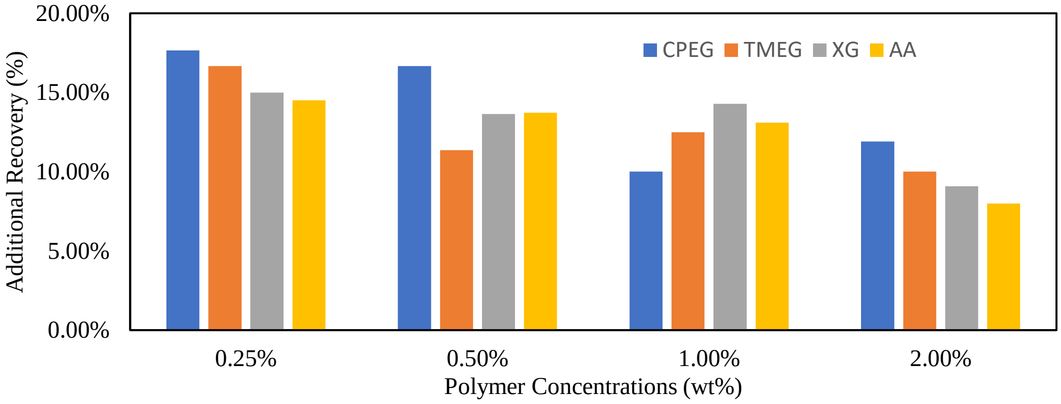


Fig. 16. Additional recovery at various concentrations of polymer

Conclusion

From the conducted study, we can conclude that CPEG, AA, TMEG, and XG are all polysaccharides, compatible in soft brine and can be used in CEOR. At all concentrations, XG recorded the highest viscosity in solution. Salinity has proven to have impacts on the viscosity of polymers. Adsorption rate of polymers increases with an 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 in the study, as it yielded additional 17.65%, while 0.25wt% TME, XG, and AA recorded 16.67%, 15%, and 14.50% additional recoveries, respectively.

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