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A comparative study on natural vs. synthesized polymers combined with silica nanoparticles to maximize secondary oil recovery

Zeyad Tamer Elshony,[a] Waleed Abd-Alsabour Ali,[a] Mohamed Sadek Hamedi,[a] Attia Mahmoud Attia[a]*

[a]Department of Petroleum and gas Technology, Faculty of Energy and Environmental Engineering (FEEE), The British University in Egypt (BUE), El-Shorouk City, Cairo 11837, Egypt

Abstract

Polymer flooding is a well-established technique for enhancing oil recovery from reservoirs. In this study, we investigate the performance of two different polymers, Xanthan Gum, and HPAM for secondary oil recovery in the sand pack. The effects of polymer concentration and high salinity on oil recovery are studied. The polymers are characterized using various measurements and tests, including viscosity, shear rate, and interfacial tension. The sand pack flooding experiments are conducted under various conditions, including varying polymer slugs, and nano-silica (silicon dioxide SiO_2) concentration. The results are analyzed to determine the optimal conditions for polymer flooding for enhanced oil recovery. The Xanthan Gum's highest oil recovery was at 1250 PPM (69.1% oil recovery) and the HPAM's highest oil recovery was at 1625 PPM (69% oil recovery) and when combined with SiO2 with a concentration of 0.02475 wt% which for Xanthan gum at 1250 PPM gave 74.875% oil recovery and for HPAM at 1625 ppm gave 72.768% oil recovery. Xanthan gum had more resistance to viscosity reduction under high salinity conditions which was not the case with HPAM and thus the xanthan gum had higher oil recovery at lower polymer concentrations.

Keywords: HPAM; Nano Silica (SiO_2); Oil Recovery; Polymer Flooding; Xanthan Gum

1. Introduction

Enhanced Oil Recovery (EOR) techniques have been employed to increase the recovery factor of oil reservoirs. Among these techniques, polymer flooding has gained attention due to its effectiveness in enhancing oil recovery. The process involves injecting water-soluble polymers into the reservoir to increase the viscosity of the injected fluid, reduce the mobility ratio, and improve sweep efficiency. According to (Gomaa et al., 2022), the effectiveness of the displacement operations of oil and the oil volume produced following the primary recovery stage is conditional upon vertical, areal, and displacement sweep efficiencies. Several polymers have been used for this purpose, including Xanthan Gum, and Partially Hydrolyzed Polyacrylamide (HPAM). These polymers have different characteristics and properties that influence their effectiveness in enhancing oil recovery. According to (Moussa & Attia, 2016), one of the crucial steps in the planning phase of a certain polymer flooding project is the determination of the optimum polymer concentration as it have a significant impact on both economic and technical feasibility and reliability of the project. Additionally, (Mahran et al., 2018) investigated those parameters such as reservoir temperature, formation type and its brine salinity as well as the viscosity of oil must be taken into consideration in any polymer flooding project. (Attia, 2007) came up with a summary that shows that there are various empirical investigations have been conducted on the utilization of viscous polymer solutions. The studies concluded that the mobility ratio between the displaced and displacing fluids will increase as the polymer solution viscosity increases. As most of polymers used in EOR projects lose their ability of viscosifying and degrade at harsh reservoir conditions (HSHT) in which the salinity and temperature are very high, (Attia & Musa, 2015) conducted a rheological study of Xanthan gum prior to and following its integration with Sodium Magnesium Silicate. This laboratory investigation was carried out under specified conditions of temperatures and salinities. The study was performed at temperatures of 25 and 60 degrees Celsius and salinity of 0, 3.4, 10, 15, and 20 weight percent of NaCl. Afterwards, the results indicate that the used polymers are effectively influenced by temperatures, and salinity, in addition to the shear rates. Subsequently, the results demonstrated that factors such as temperatures, shear rates, and salinity have a significant impact on the polymers viscosity being utilized. A strong salinity and thermal resistance have been proven on Xanthan gum throughout a wide range of shear rates, including high, medium, and low values. Moreover, the incorporation of sodium and magnesium silicate nanoparticles to the utilized polymer resulted in enhanced viscosity solutions and showed improved thermal stability and resistance to shear compared to conventional xanthan gum especially at high salinity.

(Keiko et al., 2015) conducted a study on polymer flooding for oil recovery using the commercial simulator STARS. Their reservoir model had dimensions of 20x20x10 cm^3 with a grid of 20 blocks in the direction I and J, and 10 blocks in the direction K. The model was homogeneous with 1000 mD permeability, porosity of 0.20, temperature of 24°C, initial water saturation of 0.2, and residual oil saturation of 0.3. The production scheme consisted of two vertical wells, one injector, and one producer,

*Corresponding author e-mail: attia.attia@bue.edu.eg.; (Attia M. Attia).
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arranged to represent a quarter of five spots. The maximum injection pressure was 5000 kPa with a maximum injection flow rate of 0.425 cm^3/min. The pressure at the producer was limited to 101 kPa.

The polymer solution used was based on HPAM polymer with a density of 1.11 g/cm^3, viscosity of 15 cp for a shear rate of 10 s^{-1}, and concentration of 2,500 ppm. The water used had a salinity of 100,000 ppm, and the oil in the reservoir was characterized as heavy oil with 20°API gravity which refers to the American Petroleum Institute that is considered a perfect indicator of the quality and grade of oil and a viscosity of 23.86 cp. The researchers made modifications to their study by varying the polymer slug size, start times for injection of the polymer slug, relative permeability of water at residual oil saturation, polymer viscosity, residual oil saturation, and initial water saturation.

According to (Castro-Garcia et al., 2016), the two types of polymers used for field applications are polysaccharides and polyacrylamides, with HAM being the most widely used polymer in EOR applications. The HPAM structure stretches and raises the viscosity of the solution in freshwater due to the charge repulsion of the carboxylic group. In contrast, in high salinity water, the HAM structure is compressed resulting in solutions with lower viscosity. The researchers reported that polymers of hydrolyzed acrylamide should not precipitate in reservoirs with a temperature until 100°C and water with calcium content below 200 ppm. For high calcium concentrations and high temperatures, copolymers of acrylamide (AMPS) improved with sodium metaborate, and sodium carbonate have been evaluated. Viscosity measurements were taken on HPAM polymer solutions with a viscosity of 15 cp for a shear rate of 10 s^{-1}, a concentration of 2,500 ppm, and a density of 1.11 g/cm^3. The salinity of water used in the experiment was 100,000 ppm, while the viscosity of the heavy oil used was 23.86 cp. The Yarigui-Cantagallo Field was identified as having appropriate characteristics to implement polymer and surfactant-polymer flooding technologies as enhanced recovery methods. Additionally, the researchers observed that polymer flooding may reduce relative permeability of the aqueous phase and residual oil saturation is lower after a polymer flooding process than after an analogous waterflooding process.

(Silveira et al., 2018) polymer concentration used in the experiment was not explicitly mentioned in the provided text. However, it is mentioned that HPAM-ATBS was used as the polymer and its concentration was determined based on the target viscosity for the injection fluid (10 mPa.s at 7.8 s^{-1}). The water source for making and determining the polymer concentration was the produced water (SPW) with a total dissolved solids concentration of 104,800 ppm, which was prepared to represent the reservoir fluids at test conditions (60°C). (Dano et al., 2019) conducted a simulation study on Polymer flooding for EOR, where the reservoir had 30000 ppm salinity, Oil gravity was 26 API, and the HPAM polymer concentration ranged from 1000 to 5000 ppm. The viscosity range was from 4 cP to 25 cP, and the injectivity and pore volume slug size injected was 25%, 37.5%, 50%, and 75% PV. According to the study conducted by (Petro et al., n.d.) , the use of the natural biopolymer Xanthan has great performance in enhanced techniques of oil recovery. However, while using it under harsh conditions, it encounters some kind of thermal and microbial degradation. In the study, grafted xanthan with poly(acrylamide) polymer was used in which the potassium per sulfate is present and acts as the water-soluble initiator. Numerous spectroscopic techniques such as (FTIR) spectroscopy besides nuclear magnetic resonance (1H-NMR) are used with the intention of Structure determination. Rheological and solution behavior and properties investigated under the simulated reservoir conditions that the polymer would encounter including thermal, mechanical, and chemical degradation in order to assess the potential of the polymer to operate as a chemical flooding agent. Subsequently, the results proved that this polymer can be deemed a viable EOR candidate, as a recovery factor of 18% was achieved when the flooding tests were carried out on an unconsolidated sand-packed model.

(Al-Shakry et al., 2018) investigated the effect of polymer flooding on enhanced oil recovery. They used a synthetic reservoir rock sample and a crude oil sample obtained from the Rumaila oilfield. The study was carried out in a core flooding apparatus under different salinities (5,000, 10,000, and 15,000 ppm) and two polymer concentrations (500 and 1000 ppm). The measurements were conducted in pp. The experiment was performed by first preparing the polymer solution by dissolving the polymer in brine water. The synthetic core was then saturated with crude oil, followed by flooding with brine to achieve initial water saturation. Polymer flooding was carried out under a constant injection rate and differential pressure. The effluent samples were collected and analyzed for oil recovery, residual oil saturation, and water-oil relative permeability.

(Sayyouh et al., 1993) conducted a study on the significance of alkaline and polymer on the Petrostep HMW surfactants phase behavior in crude oil-brine systems after achieving equilibrium at temperatures of 25 and 70°C. The study showed that the miscibility increases when the reservoir salinity was 23% NaCl and while using the NaOH and increasing its concentration from 0.5 % to 1.0 %. On the other side, the miscibility decreases as the concentration of NaCl increases from 3. 84 % to 23%. Furthermore, the miscibility decreased as the temperature increased and when the isopropyl alcohol was used. The conducted study proved that the polymer presences enhances the miscibility of water-rich side and likewise decreases the miscibility of oil-rich side.

In (Dukeran et al., 2018) exact polymer and salinity concentration used in this paper is not provided. However, the paper does mention that three types of polymer were used in the models, Flopaam 3130S, 3430S, and 3630S, and that in the core flooding simulation, the optimal range of polymer concentration was estimated to be between 500ppm to 5000ppm. The paper also notes that the effect of polymer concentration on recovery factor and net present value was analyzed in phase 2, but the specific concentration values used are not provided. Similarly, the paper does not provide the specific salinity concentration used. (Juárez et al., 2020) used 1D homogeneous Bentheimer cores of similar properties for their experimental study. The cores were oil flooded using crude oil with a viscosity of μo = 120 cP at T=60°C and aged to obtain intermediate wet conditions. The polymer used was a partially hydrolysed polyacrylamide (HPAM) dissolved in a moderate salinity brine. The polymer solutions were prepared at concentrations ranging from 1500ppm to 3000ppm, covering a large range of viscosity ratios (from 2 to 18) which correspond to end-point mobility ratios of 0.5 and 5.4, respectively. The synthetic brines used had a TDS of 28,288ppm and a pH of 6.0, and the polymer solution was prepared through a series of steps including the preparation of a mother solution, dilution to the required concentration, pre-degradation, and filtration. The cores used were 200mm long and had a square cross-section of 40x40mm^2, wrapped by non-wetting epoxy resin reinforced by glass fibre.

(Elsaeed Shimaa et al., 2021) developed and evaluated two biodegradable biopolymers (GH and GBH composite) for polymer flooding in high-salinity reservoirs. The polymers showed successful grafting and incorporation of biochar, with GH exhibiting higher thermal stability than GG. Flooding tests using high-salinity conditions achieved an ultimate oil recovery of 58.42% through waterflooding. Optimal concentrations of 2 g/L of GHB and 5 g/L of GH increased enhanced oil recovery to 64.74% and 67.37% (GHB) and 70.53% and 72.11% (GH) in secondary and tertiary recoveries, respectively.

(Hazarika et al., 2023) conducted a field study in the Assam basin to evaluate the efficiency of polyacrylamide (PAM) and xanthan gum (XG) as chemical agents for polymer flooding. Core flooding experiments were performed, and the rheological properties of the polymers were analyzed in a 3000 ppm brine at different concentrations. Optimal concentrations of 1500 ppm for PAM and 500 ppm for XG in a 3000 ppm brine yielded the best results. PAM exhibited viscoelastic behavior and higher yield strength, leading to better control of reservoir heterogeneity. Core flooding simulations demonstrated its piston-like movement, improving macroscopic sweep and microscopic displacement efficiency. Similarly, XG exhibited comparable behaviour but with lower yield strength. It displayed shear thinning behavior at lower shear rates and constant shear stress at higher rates, resulting in larger microscopic displacement and sweep efficiencies compared to PAM. In summary, the study confirmed the effectiveness of polymer flooding, with PAM and XG showing potential as chemical agents for enhanced oil recovery in the Assam basin.

The combination of polymer flooding with nanoparticles and/or other chemicals, such as alkaline and surfactants, has been found to further enhance oil recovery by providing additional abilities to the flooding process, including wettability alteration. (Druetta & Picchioni, 2019) introduced a novel technique for a two-phase 2D reservoir consisting of five components. Through simulation, they investigated the impact of polymer architecture on the recovery factor and studied the effect of adding nanoparticles on enhanced oil recovery. The study also calculated the physical properties of the novel polymer. The results showed that when nanoparticles were injected first, they altered the rock wettability to water-wet or strongly water-wet conditions. This led to a reduction in interfacial tension and increased the efficiency of the subsequent polymer slug in sweeping the oil. Overall, the integration of nanotechnology into enhanced polymer flooding was considered a novel and improved technique for enhanced oil recovery. The advantages and synergistic effects of combining polymers with nanotechnology and other chemicals were highlighted.

(Mahran, Attia, Zadeh, et al., 2022) conducted a study on a novel stable terpolymer synthesized by grafting vinyl benzyl starch onto poly(acrylamide/acrylic acid/acrylacyloxyethyltrimethyl ammonium chloride) using free radical polymerization in the presence of silica nanoparticles and a dimethylphenylvinylsilane derivative. The chemical structure of the polymer composite and modified starch was confirmed through FTIR and 1H NMR spectroscopies. TEM and DLS analyses demonstrated that the presence of silica nanoparticles at various concentrations reduced the latex size. Thermal gravimetric analysis (TGA) was performed to assess the thermal properties of the polymer, and rheological measurements indicated its reasonable resistance to temperature, shear, and salt due to its amphoteric structure. The study found that an optimum polymer concentration of 3 g/L resulted in an oil recovery factor of 43%. These findings suggest that the novel polymer holds promise as an effective agent for enhanced oil recovery in harsh reservoir conditions.

To further show the capability of polymer-nano flood and its ability to alter the wettability (Soliman et al., 2020) investigated the use of xanthan gum (XG) and its combinations with silica derivatives as chemical flooding agents and wettability modifiers. The study showed that the silica derivatives improved the rheological characteristics of XG, making it more resistant to high temperatures and salinities. The presence of silica precursors altered the wettability of the cores, enhancing oil recovery. Increasing the XG concentration improved oil recovery, while for XG/SiO2, the optimum concentration was 1.5 g/L. Overall, XG-g-silica proved to be a practical agent for enhancing oil recovery and altering wettability.

Furthermore, (Agi et al., 2020) conducted a study on the effect of polymeric nanofluid on enhanced oil recovery. They synthesized Cissus populnea nanoparticles (CPNP) from Cissus populnea (CP) natural polymer using ascorbic acid. The physical characteristics of CPNP and CP, including size distribution, were examined using DLS and TEM. The displacement procedure was scaled down, and the effects of process factors were investigated. The rheology of CPNP was compared to CP solution and commercial polymer xanthan. The interfacial tension (IFT) properties of CPNP were studied at different concentrations, temperatures, and salinities, including the interaction with ultrasound. The wetting alteration efficiency of CPNP on initially oil-wet sandstone cores was evaluated using the Sessile drop contact angle method. The experimental results indicated that particle shape, concentration, and surface charge influenced the rheology of the system. Shear-thinning and pseudoplastic behavior were observed. The interfacial tension decreased with increasing concentration, electrolyte concentration, and temperature. CPNP demonstrated the ability to alter sandstone wettability at low concentrations, high salinity, and high temperatures. It successfully increased oil recovery by 26% and showed particular effectiveness in recovering residual oil under high-temperature and high-pressure reservoir conditions. The study revealed relationships between Bond number, Sor, capillary number, and IFT. Energy consumption and cost estimation demonstrated that the proposed novel polymeric nanofluid was more economical compared to existing enhanced oil recovery chemicals. According to ((G. E. Azmi et al., 2022), rock wettability and permeability are strongly affected by the chemical adsorption within the hydrocarbon reservoirs which in turn affect the overall production of the oil. This was shown through the study that used both sodium dodecylbenzenesulfonate (SDBS) anionic surfactant (SDBS) and Xanthan gum (XG) as displacement fluids. The unconsolidated sandstone (SS) pack model was employed to compute the reduction in permeability in addition to the chemical adsorption on the surface of the rock. Also, the study investigated the impact of combining nano silica particles (NSPs) with the fluid being injected on the adsorption of the rock. The conclusions of the study came up with when the chemical concentration at the applied salinities of 0, 3.5, 5, and 10% of the displacement fluids increased, the adsorption amount of both SDBS and XG on the surface of the rock will also increase. Moreover, the results shown that as the concentrations of both SDBS and XG increase, the permeability reduction will also increase.

(Taborda et al., 2021) investigated the effect of silica nanoparticle surface acidity on the thermal degradation of hydrolyzed polyacrylamide (HPAM) solutions for enhanced oil recovery. Silica nanoparticles were modified with HCl (SiO_2A) and NaOH (SiO_2B). The nanoparticles' characteristics were analyzed, and adsorption isotherms were used to study their interaction with the polymer. Rheological tests and core flooding experiments were conducted. Results showed that SiO_2B nanoparticles had stronger interactions with HPAM, leading to a more degradation-resistant polymer network. The addition of nanoparticles reduced viscosity, with SiO_2B exhibiting the lowest reduction. Core flooding tests demonstrated reduced polymer retention and an additional 30% oil recovery with the aged polymer solution containing nanoparticles. This study emphasizes the importance of silica nanoparticle surface acidity in controlling HPAM degradation and its implications for enhanced oil recovery.

In this regard,(alibadi et al., 2022) conducted a study on the uses of rice husk ash and commercial nano silica in the PMMA/silica nanocomposite. The characterization was carried out with different SiO_2 weight loadings using hardness, impact testing, flexural strength, and SEM. For maximum strength, he had 0.05wt% for impact strength and 0.1wt% for flexural strength.

In their study, (Keykhosravi et al., 2021) investigated the potential of Anatase TiO_2 nanoparticles-induced xanthan gum (XG) polymer as a nano-polymer suspension for enhanced oil recovery (EOR) in carbonates. They examined the viscosity and stability of the XG polymer with and without nanoparticles, measured interfacial tension, evaluated wettability alteration, and conducted oil displacement experiments using carbonate rock cores. Results showed that increasing the XG polymer concentration led to a transition from Newtonian to non-Newtonian behavior. Anatase TiO_2 nanoparticles helped recover viscosity reduction caused by thermal degradation and salt impact. The nanoparticles remained thermally stable and improved the wettability of the rock, achieving a strong water-wet state. Core flooding experiments demonstrated that the nano-polymer suspension resulted in 25% more oil recovery compared to polymer flooding without nanoparticles, attributed to improved water viscosity and wettability alteration. While the nano-polymer suspension reduced interfacial tension, it was not the primary mechanism for EOR in carbonates. Overall, the study highlighted the potential of Anatase TiO_2 nanoparticles-induced XG polymer as a promising approach for EOR in carbonate reservoirs.

In their study, (Mahran, Attia, & Saha, 2022) developed a thermo-responsive nanocomposite for enhanced oil recovery (EOR) under harsh high temperature and high salinity (HTHS) conditions. The nanocomposite was synthesized using a high oleic acid waste vegetable oil (WVO) and a green route transesterification reaction. Characterization methods confirmed the presence of specific functional groups in the synthesized monomer. Through copolymerization with other compounds, the nanocomposite exhibited pouncing thermo-thickening behavior and superior viscosifying properties at low polymer concentrations. It demonstrated excellent performance even in extremely saline environments. Core flooding tests conducted under HTHS conditions showed significant oil recovery with the nanocomposite, demonstrating its potential for effective EOR in challenging reservoir conditions.

The study conducted by (El-Hoshoudy et al., 2019) focused on the effectiveness of xanthan gum (XG) polymer, along with silicon dioxide nanoparticles and alkaline solutions, in enhancing oil recovery under high temperature and high salinity conditions. The experiments were carried out using a sand pack as the porous medium, with a temperature of 71.1°C and XG concentration of 1000 ppm. Two displacement methods, tertiary and secondary recovery, were tested. The results showed that increasing the polymer concentration led to higher viscosity, while viscosity decreased with increasing salinity or temperature. XG demonstrated its capability to perform well in harsh conditions. The secondary recovery method was found to be more efficient, achieving 7% to 10% higher recovery compared to the tertiary method. Through testing various mixtures, the optimal concentration for achieving a recovery of 82% was determined to be 1000 ppm polymer, 1 wt% NaOH, and a low concentration of 0.05 wt% nanoparticles. The study also revealed that the polymer had no impact on wettability but increasing nanoparticle concentration resulted in a shift towards a more water-wet state. A study performed by (alibadi et al., 2022) In this work, dynamic flooding studies were carried out in order to understand chemical adsorption into the sandstone formations by use of bio-polymer, XG, and anionic surfactant, SDBS. The work conducted understood that the rate of chemical absorption was directly proportional to the concentration of biopolymers and surfactants. In the co-injectant role, D nano-silica particles boosted the binding of polymers by 67.8% and those of surfactants by 60.2%. The results for adsorption optimisation on this case study showed a recovery factor of 78.9% in the polymer bending case, 67% in the surfactant case, and 77% in the polymer-surfactant blend case. This is contrasted with the waterflooding base case, which gives a recovery factor of 58%.

1.1. Design Expert

In order to conduct a comprehensive study, it is required to use a robust software tool that facilitates experimental design, data collection, analysis, modelling, optimization, and visualization. The software offers an array of capabilities and features that can greatly assist in the research investigation. It facilitates the creation of efficient experimental designs, enables streamlined data collection and entry, provides robust statistical analysis and modelling capabilities, supports model optimization, and offers intuitive visualizations for result interpretation, where:

1. Creating design: Using statistical analysis it generates a design matrix.

2. Collecting data: According to the generated design matrix the actual experiment is performed and then the collecting of the response data occurs.
3. Data Entry: The data collected is recorded in the design matrix.
4. Analysis and Modeling: It builds a model to represent the relationship between the factors entered and the responses using ANN by analyzing the data.
5. Optimizing Model: The software offers tools to optimize the system being studied to identify the optimal factor settings that maximize the desired response which in our case the oil recovery.
6. Visualization and Interpretation: It provides visualizations and graphical tools, such as 3D plots, interaction plots, and contour plots.

2. Work Objective

In High salinity reservoirs, the HPAM experiences viscosity reduction, which reduces the oil recovery and thus Xanthan gum is used because it can withstand high salinities, but it is more expensive than HPAM. By the addition of Silicon Dioxide SiO_2 (nanoparticles) to both of the polymer solutions it’s possible to lower the viscosity reduction and give higher oil recoveries. This research aims to give a comparison between Xanthan Gum (natural) and HPAM (synthesized) under various conditions at a temperature of 30˚C and study their effect on oil recovery in the secondary stage, observe the effect of silicon dioxide SiO_2 (nanoparticles) on the oil recovery, use Silicon dioxide combined with each of the polymers and observe their effects on the oil recovery.

3. Methodology

3.1. Chemicals used

Table 1: Oil properties (lab measured)

Oil Properties	Acid number	0.8 mg KOH/gm oil
	Viscosity	2.464 cp at 30ºC and 1 atm
	Density	0.814 gm/cm^3 at 30ºC and 1 atm
	API	41.81º

Table 2: Polymers and nanoparticles concentrations

	Polymers		Nanoparticles
Type	HPAM (ppm)	Xanthan Gum (ppm)	Silicon Dioxide (SiO_2) wt%
Concentrations	500	500	0.02475
	747.5	747.5	
	1002.5	1002.5	0.049962
	1250	1250	0.075
	1625	1625	0.1125
	2000	2000	0.15

3.2. Displacement Apparatus

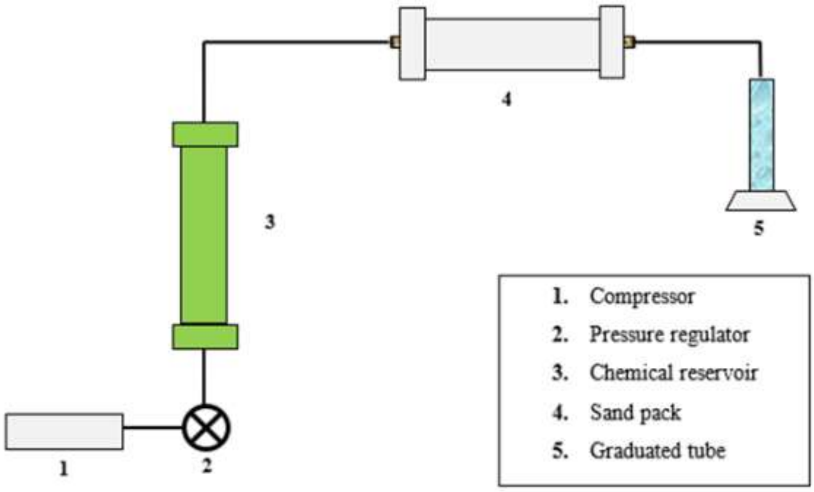

Fig. 1. Displacement apparatus

Figure 1. Shows a diagram of the displacement apparatus. The sand pack Properties can be found in Table 3. The sand pack was fitted with screens and filters near the outlet to prevent any porous medium outbreaks. The effluent fluid discharged from the sand pack was collected in a graduated tube. The inlet was connected to a chemical reservoir tank containing either polymer or nano or both or brine, and the chemical reservoir tank was connected from the other end to a pressure regulator in order to control and measure the pressure further the regulator was connected to a nitrogen compressor. The sand used in the packing was 600 µ.m ≤ sand size < 700 µ.m.

Table 3: Properties of the sand pack model, brine, formation water salinity used.

Properties, unit	Values
Sand size, micrometer	600 µ.m ≤ sand size < 700 µ.m
Length, cm	27.5
Diameter, cm	5
Area, cm^2	19.635
Bulk volume, cm^3	587
Pore volume, cm^3	160
Porosity, %	27.257
Permeability, mD	688.697
Formation Water Salinity, ppm	150,000
Injected Brine Salinity, ppm	35,000

3.3. Displacement Procedures

During the sand packing procedure, the sand pack was fully saturated with brine. Subsequently, brine was introduced to assess the permeability of the model before the chemical injection. Next, which is known as reservoir initiation, the oil was injected to displace the brine, and the oil effluent was gathered to ascertain the amount of oil that displaced the brine. To displace the oil in the reservoir (sand pack model), brine was reintroduced as a water flooding process and collecting the new oil samples with the time for each of them while maintaining the pressure and the flow rate. The steps were repeated for the polymer and nano and combined floods with only the displacing fluid being changed in the second phase (oil displacement phase).

A summary of the displacement floods can be found in Table 5. It is important to note that all solutions were freshly prepared and consistently maintained prior to the experiments.

3.4. Solution Preparation

The design matrix was generated using Design Expert to generate the chemical concentrations that will be used in the flooding. The amount of polymer needed is weighted using the balance with high precision sensitive balance. The amount weighed is added to saline water with a salinity of 35000 ppm (the salt used was NaCl) and then it's mixed using a stirrer. Chemical solutions are prepared right before flooding to prevent any effects from air exposure or precipitation and for the nano solutions, they are kept on the stirrer all the time of the flood to keep the nano in a soluble state.

3.5. The Interfacial Tension Calculation (IFT)

The IFT calculations were carried out using EZTensiometer surface tension calculation software v2-0 by Temco, Inc by entering the maximum balance reading obtained from the EZTensiometer by ROD device and recording the interfacial tension measurement.

4. Results and Discussion

4.1. IFT Measurement

Table 4: Measurements of the IFT of polymers and nano used.

Polymers and nano used	*Chemical Concentration, wt%*	*IFT mN/m*
Xanthan Gum	500	28.151
	747.5	24.65
	1002.5	17.671
	1250	22.263
	1625	19.607
	2000	17.353
HPAM	500	75.342
	747.5	41.465
	1002.5	40
	1250	35.798
	1625	31.746
	2000	23.279
Nano silica	0.02475	28.385
(Silicon Dioxide SiO_2)	0.0499	14.564
	0.075	10.789
	0.1125	4.82939
	0.15	19.0236

The IFT between oil and brine was 39.18 mN/m. The IFT at the optimum concentration of Xanthan Gum of 1250 was 22.263 mN/m. While the IFT at the optimum concentration of HPAM of 1625 was 31.746 mN/m. The IFT of the optimum concentration of Silicon Dioxide (SiO_2)of 0.02475 was 28.385 mN/m.

4.2. Wettability determination

All determined Sw_i at $Kr_w = Kr_o$ are recorded in Table 5 the following will be the relative permeability saturation curves for each chemical concentration.

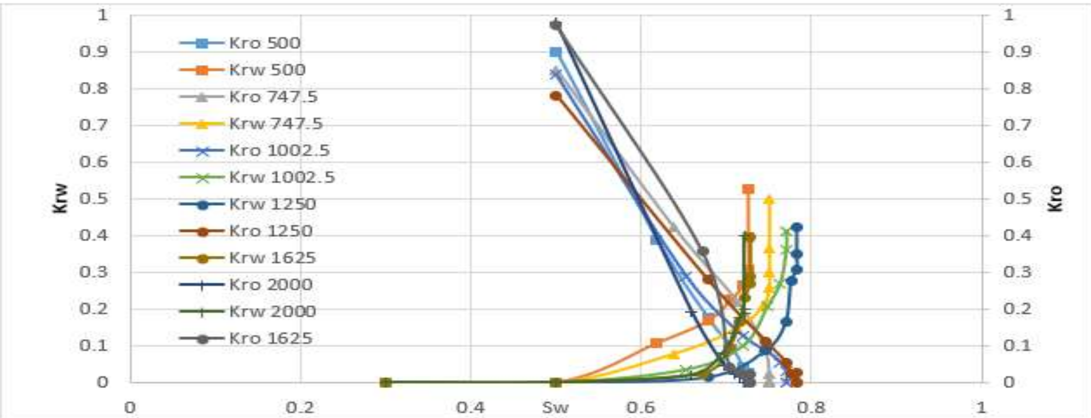

Fig. 2. Relative permeability saturation curve for Xanthan-gum

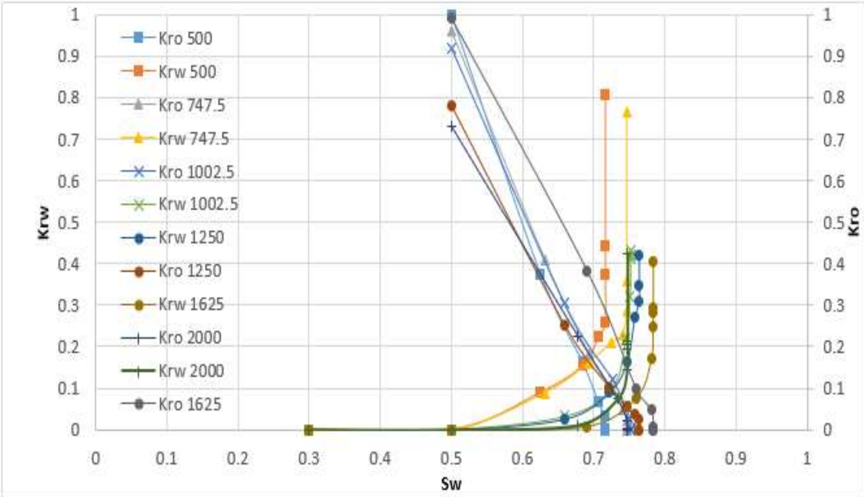

Fig. 3. Relative permeability saturation curve for HPAM

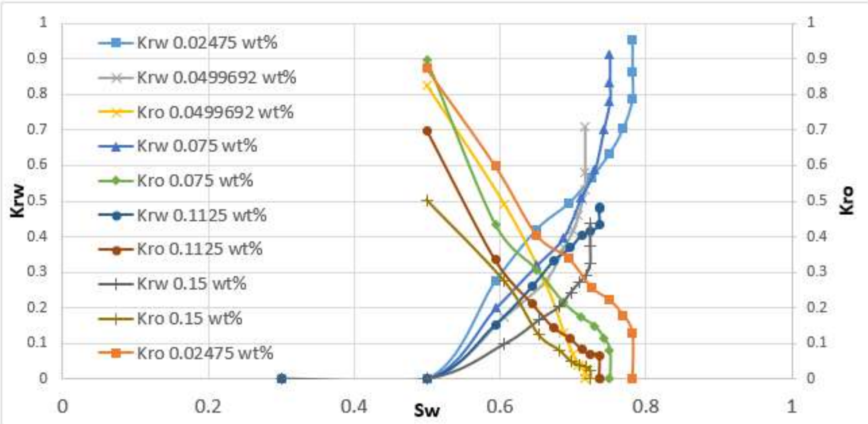

Fig. 4. Relative permeability saturation curve for silicon dioxide

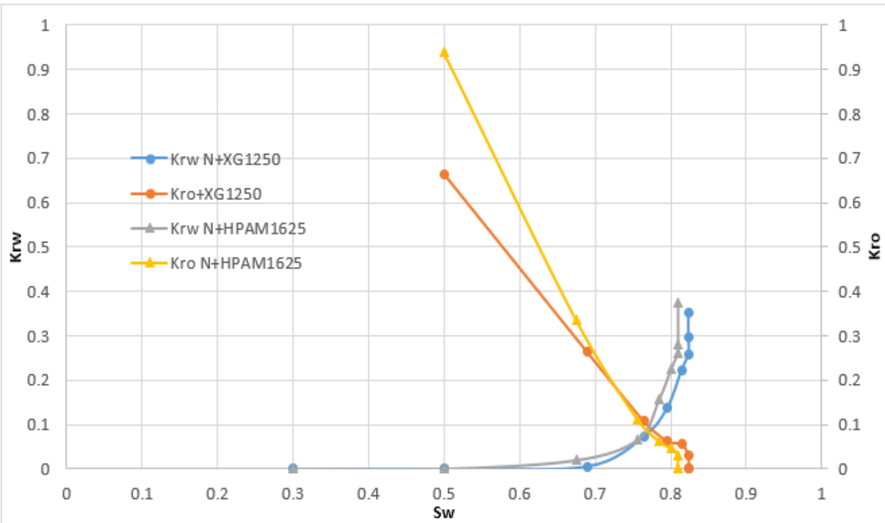

Fig. 5. Relative permeability saturation curve for Nanosilica-polymer combined.

As seen in Figures 2 and 3 and Table 5 The polymer altered the wettability of the sand pack model as the polymer solution contacted the rock surface, some polymers can adsorb onto the rock grains or form a thin polymer film. The process of adsorption can alter the surface characteristics of the rock and have an impact on its wettability to hold water. In Figures 4 and 5 the wettability was further altered by the addition of nano-silica as lowering the IFT between the displacing fluid (polymer solution) and the oil phase improves the displacement efficiency which the nanoparticles did.

4.3. Oil Recovery

The oil recovery increases with the increase of the Xanthan-Gum concentration until it reached its peak at XG-concentration of 1250 ppm (69.107%) and for HPAM it reached its peak at the HPAM concentration of 1625 ppm (69.018%) and started to decrease again due to the adsorption effect.

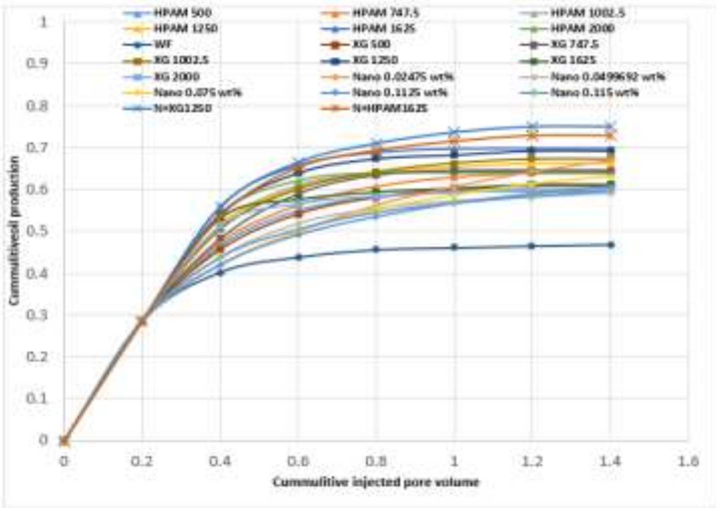

Fig. 6: Oil recovery of all chemical floods compared to water flood.

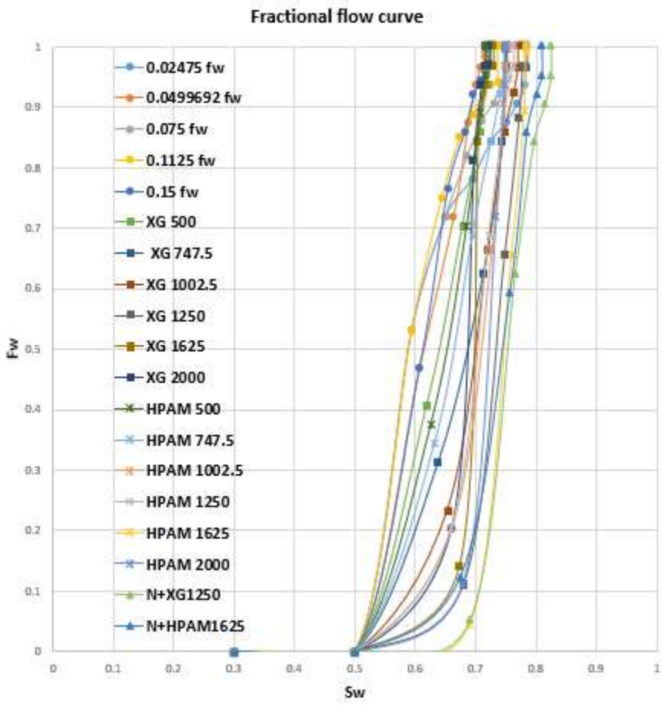

Fig. 7: Fractional flow curve

Table 5: Chemicals oil recovery, with wettability and slug properties

	Chemical concentration	Saturation (% PV)			Recovered Oil (%)	S_{wi} at $K_{rw}=K_{ro}$
		S_{oi}	S_{wc}	S_{or}		
Brine with 35,000 ppm		0.7	0.3	0.373	46.786	0.597
Xanthan Gum	500 ppm	0.7	0.3	0.275	60.714	0.679
	747.5 ppm	0.7	0.3	0249	64.375	0.727
	1002.5 ppm	0.7	0.3	0.23	67.143	0.728
	1250 ppm	0.7	0.3	0.216	69.107	0.751
	1625 ppm	0.7	0.3	0.272	61.1607	0.681
	2000 ppm	0.7	0.3	0.279	60.122	0.69
HPAM	500 ppm	0.7	0.3	0.284	59.4643	0.681
	747.5 ppm	0.7	0.3	0.253	63.839	0.699
	1002.5 ppm	0.7	0.3	0.248	64.553	0.727
	1250 ppm	0.7	0.3	0.237	66.161	0.727
	1625 ppm	0.7	0.3	0.217	69.018	0.746
	2000 ppm	0.7	0.3	0.253	63.881	0.732
Nanosilica (Silicon Dioxide SiO_2)	0.02475 Wt%	0.7	0.3	0.219	68.75	0.641
	0.075 Wt%	0.7	0.3	0.25	64.286	0.65
	0.1125 Wt%	0.7	0.3	0.264	62.321	0.612
	0.15 Wt%	0.7	0.3	0.276	60.536	0.645
	0.049 Wt%	0.7	0.3	0.284	59.464	0.66
SiO_2 (0.02475 Wt%) +XG1250		0.7	0.3	0.191	74.875	0.778
SiO_2 (0.02475 Wt%) + HPAM1625		0.7	0.3	0.176	72.768	0.769

The oil recovery increases with the increase of the Xanthan-Gum concentration until it reached its peak at XG-concentration of 1250 ppm (69.107%) and for HPAM it reached its peak at the HPAM concentration of 1625 ppm (69.018%) and started to decrease again due to the adsorption effect where at high polymer concentrations, the excess polymer molecules can lead to excessive adsorption on the rock surfaces, forming a polymer layer that hinders the flow of oil. This layer reduces the contact between the injected polymer solution and the oil, reducing oil recovery.

5. Conclusion

Based on this work, the following conclusions can be drawn:

- Xanthan gum was found to be the best polymer to be used in secondary recovery as it gave the highest oil recovery at 1250 ppm.
- HPAM is good for oil recovery but doesn't withstand high salinity conditions and experiences viscosity reduction, unlike the xanthan gum.
- Nano-silica was successful in altering the wettability and IFT of the reservoir which led to a very high oil recovery when combined with both polymers and it even caused the HPAM viscosity reduction to decrease significantly and thus increase the oil recovery.
- An unexpected observation was the polymer altering the wettability of the rock, which was a good thing, but it needs further investigation. The oil recovery was at its best when combining the optimum nano-silica concentration (0.02475 wt%) with the optimum Xanthan-gum concentration (1250 ppm) and the optimum HPAM concentration (1625 ppm) to maximize the oil recovery and results can be seen in Table 5.
- By adding the optimum nano concentration to the optimum polymer concentrations, the wettability was shifted from 0.746 in the HPAM flood to 0.769 and in the XG from 0.751 to 0.778 which led to a significant increase in the oil recovery.

6. Conflicts of interest

The authors declare that they have no known competing financial interests or personal relationships that could have influenced the work presented in this paper.

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