



(RESEARCH ARTICLE)



Performance assessment of a novel bio-based polymer for enhanced oil recovery in high salinity sandstone reservoirs

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Abstract

Polymer flooding is arguably the oldest chemical oil recovery method. The use of natural polymers in enhanced oil recovery process has gained wide acceptance due to their excellent viscosity, high resistance to challenging reservoir conditions ranging from increased salinities, temperatures and divalent cations. In recent times, research into the efficiency of green natural polymers is gaining attention as an eco-friendly, readily available and cost-effective option. In this study, the displacement efficiency of *Abelmoschus esculentus* as a natural polymer in recovering heavy crude from sandstone reservoirs was examined and a simulation model was built to replicate the laboratory model. *Abelmoschus esculentus* was cleaned, sun-dried, and grinded into powder form and enclosed in an airtight bag. The various phases were analyzed to ascertain the fluid-fluid compatibility and consistency. Polymer rheological studies was conducted at varied temperatures. Core flooding at optimum polymer concentration was considered in an oil-wet sandstone core under reservoir conditions. Results showed that the solubility of the fluids is a function of temperature. Furthermore, polymer viscosity showed a direct relationship to the polymer concentration and temperature. Polymer flooding resulted in additional recovery of 16.26 % oil initially in place (OIIP), thus affirming the efficiency of this natural polymer in recovering heavy oil. However, a viscosity enhancer is required for improved performance. The simulation model was built, and the recovery factors of both models was successfully matched.

Keywords: Natural polymer; Salinity; Polymer flooding; Divalent ions; *Abelmoschus esculentus*

1. Introduction

The ever-increasing global demand for oil due to the rapidly growing global economies requires increasing recoverable reserves which can be achieved by either exploring new reservoirs or optimising the existing matured reservoirs. However, most of the existing matured reservoirs are found in challenging environmentally sensitive areas such as (Arctic & Antarctic) or in deep formation of deep water. Optimization of oil production from the current reserves in place is more likely to happen soon owing to the number of existing mature fields and the large heavy oil reserves globally. According to [1], the heavy crude oil reserves in Nigeria alone is estimated to be about 45 billion barrels, and globally the volume of heavy oil is thrice the amount of conventional oil in place (OIIP).

The recovery of the oil reserves from mature reservoirs requires the implementation of Enhanced Oil recovery (EOR) methods. Field application data collected over the last decade reveals that thermal and chemical flooding are the most commonly EOR methods used especially in sandstone reservoirs as shown in Fig. 1. Polymer flooding is classified as a mature chemical enhanced oil recovery mechanism (EOR) with over 60 years of positive results globally. This “state of art” method of oil recovery represents the new era of chemical EOR especially for heavy crude oil. It is mainly associated with the low cost per barrel recoverable in comparison to surfactant flooding.

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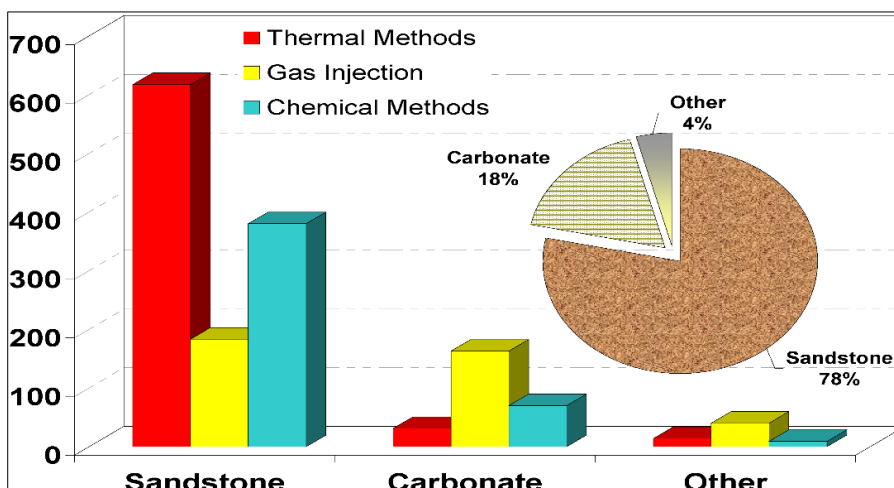


Figure 1 Enhanced Oil Recovery application in different formation [2]

Polymers are defined as macromolecules consisting of a long-chain backbone of chemically bonded repeating units of smaller molecules termed monomers [3]. Polymers can be classified based on their origin as Synthetic Polymers which are man-made polymers that have been artificially synthesized or chemically modified natural polymers and Natural Polymers which are naturally occurring polymers obtained from either plant sources (cellulose and starch) or animal sources (proteins) implying that they are biodegradable, harmless to plant life, animal life and the environment. Generally, polymers are termed ‘non-Newtonian fluids’ which is attributable to their behaviour. In general, polymer solutions are referred to as pseudoplastic owing to their shear thinning behaviour [4].

1.1. Mechanism of Polymer flooding

Polymers are principally used to increase the viscosity of the aqueous solution. Polymer flooding is designed to control the water/oil mobility ratio to improve the sweep efficiency. When the prepared polymer solution is injected in the reservoir, it decreases the water effective permeability by reducing the mobility ratio closer to 1. Often, the polymer injection when properly applied can enhance the overall sweep efficiency of the reservoir. The mobility ratio “M” is expressed as a ratio of the displacing fluid mobility ($\lambda_{\text{displacing}}$) to the ratio of displaced fluid mobility ($\lambda_{\text{displaced}}$). A decrease in the mobility ratio results in a higher oil displacement efficiency (see Fig. 2).

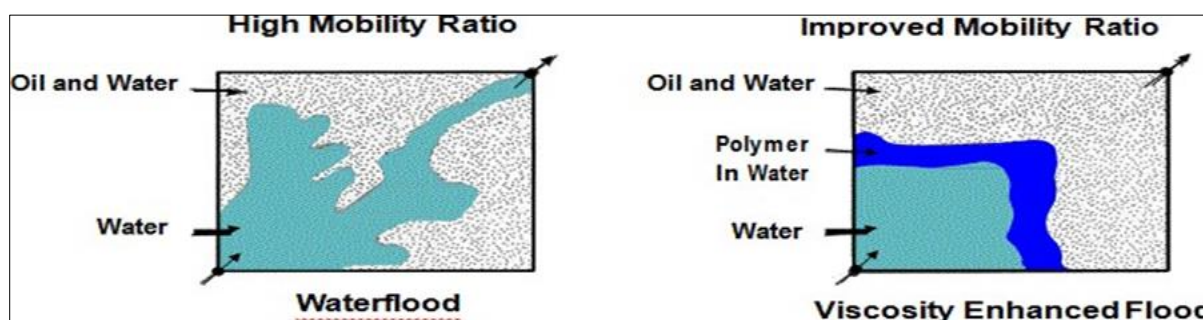


Figure 2 Mobility ratio influenced by polymer flooding [5]

The overall recovery efficiency or Sweep efficiency is classified as a measure of the volume of recoverable resources relative to the amount of resource originally in place. Initial and final in-situ volume of oil is compared to calculate the remaining fluid volume. An estimate of expected recovery efficiency can be obtained by considering the factors that contribute for the surface fluid recovery [6]. The macroscopic efficiency (E_D) denotes the measurement of the amount of fluid present in the system that can be mobilized. Table 1 shows several types of polymers used in chemical EOR processes as noted by [7].

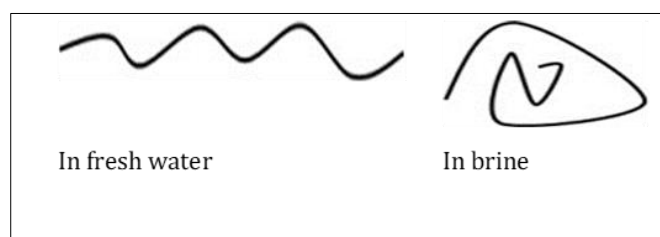
Table 1 Types of Polymers used in CEOR

Biopolymer	Synthetic	Cellulose
Xanthan gum	Polyacrylate	Hydroxyl cellulose
Guar gum; Welan gum	Polyacrylamide	Carboxymethyl cellulose
Scleroglucan	Hydrolyzed polyacrylamide	Nanocellulose

Hydrolysed Polyacrylamide is the most widely used polymer [8] having a high molecular weight than other polymer types and an increased rate of hydrolysis. The use of HPAM has recorded a significant improvement in oil recovery and water cut reduction in Daqing field in China [4]. Polyacrylamide adsorbs on the rocks surface thereby reducing the amount of polymer, but to decrease the rate of adsorption, polyacrylamide is partially hydrolysed by reacting polyacrylamide with base [9,10] resulting in Hydrolysed Polyacrylamide (HPAM). This process converts some of the amide group (CONH₂) to carboxyl groups (COO). However, HPAM is susceptible to high salinities and high temperatures, thus at higher temperatures and salinity, the viscosity of HPAM is grossly reduced.

The presence of divalent or multivalent ions (Ca²⁺ and Mg²⁺) on the rock surface reduce the polymer viscosity at a much higher intensity than the monovalent ions [11] thereby creating a favourable scenario for the poor performance of polymer in the reservoir. The polymer viscosity is commonly associated to its molecular weight. Usually, the higher the molecular weight of the polymer, the larger the hydrodynamic radius and the more effective the viscosity of the polymer. The viscosifying power of a polymer is commonly reduced by the presence of salinity on the polymer solution as reported by Sheng [12]. The effect of salinity on the polymer solution viscosity depends on the level of salinity on the polymer concentration and the molecular weight number present in the polymer. At a lower molecular weight (<10dalston), the effect of salinity tends to be more profound while in the presence of a higher molecular weight (15 – 30 Dalton's) polymer, the effect of salinity is reduced.

Sheng [4] reported that at equal concentration of both polymer types (HPAM and biopolymers), HPAM solutions have greater viscoelasticity compared to biopolymer solutions in freshwater but in saline water with salinities above 10000 ppm total dissolved solid (TDS), they lose their viscoelasticity due to the absorption of ionic charges by salt molecules thus reducing the repulsive forces which then compresses the molecular chain. According to [13], when the polymer solution is prepared using brine or high salinity produced water with a high divalent ion content, the cations compress the polymer molecules electric double layer making the molecular chain coiled within the solution as seen in Fig. 3. When the polymer molecular chain coiled up, the effectiveness and performance of the solution viscosity significantly decrease.

**Figure 3** The effect of brine in the polymer solution [13]

Muhammed *et al.* [9] further reported that biopolymers are better polymers than anionic polyacrylamides (PAM) because they are less susceptible to salinity and mechanical shear giving rise to a higher viscous fluid at salinities greater than 10000 ppm compared to polyacrylamides.

Abelmoschus esculentus is an agricultural produce that is grown in tropical or warm temperate regions. It is a polysaccharide (natural polymer) that serves majorly as a food (vegetable) source and recently, in the polymer industry [14]. The oil extracted from okro plant as reported by [15] can serve as a source of biofuel. Adetuyi *et al.* [16] noted that *Abelmoschus esculentus* is a natural polymer that contains saponin, a natural surfactant, thus having a dual function. The effectiveness of several natural polymers such as Okro, Ogbono, and Gum Arabic in improving sweep efficiency was investigated by [17, 18,19], where they all reported that Okro gave the best recovery. In their study of Okra gum, Zaharuddin *et al.* [20] reported that O-H group is the main functional group which is responsible for its hydrophilic

characteristics. They also reported that Okro gum which is a good binder has a high viscosity of 62.32 cP at 0.5% conc. and 228.78 cP at 1.0 % conc. respectively, noting that it is thermally stability at 60°C and below. Uzoho *et al.* [21] reported its efficacy in displacing residual oil at medium salinity (20000 ppm) and when compared with other natural polymers, *Abelmoschus esculentus* gave the lowest permeability impairment. Though this natural polymer has been used as a recovery agent in chemical enhanced oil recovery, however, its effectiveness in recovering heavy oil at reservoir temperatures and higher salinities has not been investigated.

This study is aimed at evaluating the oil recovery efficiency of this natural polymer, *Abelmoschus esculentus* for a heavy crude, high temperature sandstone reservoir and to develop a model to simulate this process and verify the laboratory model.

2. Material and methods

2.1. Materials

Abelmoschus esculentus (okro plant) was obtained from the farmer's market at Kpansia (4.9240°N, 6.3148°E) in Yenagoa LGA, Bayelsa State, Nigeria. Sodium chloride with a molar mass of 58.44 g/mol, potassium chloride (molar mass of 74.55 g/mol), calcium chloride and magnesium chloride both having molar masses of 110.98 g/mol and 95.21 g/mol respectively, and Toluene of high pure grade were obtained from BDH chemicals Ltd. Distilled water with a pH of 6.2 and a conductivity of 30 μ S/cm was used throughout the experimental work in preparing the brine solution. Sandstone core plug was gotten from oilfield X in southern Nigeria. Data obtained from X-ray diffraction (XRD) and thin sections analysis indicates that the core sample is mainly composed of quartz and kaolinite with minor traces of illite.

The apparatus used include water bath, magnetic stirrer, thermometer, pH meter, filter paper, funnels, glass beakers, weighing scale, masking tape, digital Vernier caliper, hand gloves, glass test tubes, glass pipettes, Soxhlet extractor, Rheometer-Bohlin Gemini, Hamilton beech Mixer, Hydrometer, Ostwald's viscometer, core flooding equipment and Eclipse 100 reservoir simulation software.

2.2. Methods

The methods adopted for this work include preparation of natural polymer sample, preparation of formulated brine, characterisation of crude oil, evaluation of rheological properties, phase behaviour studies, core flooding and simulation studies. All experimental analysis were carried out in the Reservoir Engineering laboratory of Niger Delta University.

2.3. Preparation of polymer sample

Natural polymer, *Abelmoschus esculentus* purchased from the market was properly washed, sliced into smaller pieces and then sun-dried for 7days at a temperature of 32°C to reduce the moisture content. Thereafter, the sample was pulverised, packed and sealed in an airtight container to prevent air and/or contamination. The polymer-brine solution was obtained by diluting the polymer sample in brine. Different concentrations of the polymer sample ranging from 1000 to 10000 ppm were weighed into glass bottles each containing 100 ml of the brine solution. Each of the mixture was vigorously stirred with the aid of a mechanical stirrer at 500 rpm for 2 hours to ensure a homogenous mixture. The polymer-brine solutions were then allowed to settle for 24 hours and with the aid of a 1.2-micron Millipore filter paper, each solution was filtered to remove any cellular debris and impurities present in the aqueous solution.

2.4. Preparation of Formulated Brine

Table 2 Composition of Brine

Component	Concentration (mg/l)
NaCl	30,000
KCl	5,000
MgCl ₂	2,000
CaCl ₂	3,000
TDS	40,000

Brine was formulated in the laboratory to simulate actual formation brine. The brine contained varying concentrations of sodium chloride, potassium chloride, calcium and magnesium chloride and a total dissolved solid (TDS) of 40,000 mg/l with 5,000 mg/l being total concentrations of divalent ions: Ca^{2+} and Mg^{2+} . Oruwori and Ikiensikimama [22] reported that typical salinity values for sandstone and carbonate reservoirs are 30,000 ppm and 90,000 ppm respectively. Brine with higher salinity value of 40,000 ppm was formulated to depict a high salinity sandstone reservoir. Varied grams of NaCl, KCl, MgCl_2 and CaCl_2 as outlined in Table 2 was measured and gradually added into a beaker filled with 1000 ml of deionized water. The solution was continuously stirred using a magnetic stirrer at 20 °C temperature until the salts had completely dissolved. Using a filter paper, the brine solution was filtered into a volumetric flask and properly labelled 'Formulated brine'.

2.5. Characterisation of Crude oil Sample

The crude oil used for this study was obtained from an oil field in the Niger Delta region of Nigeria. The crude oil sample was characterised to determine its viscosity, specific gravity, American Petroleum Institute (API) gravity at ambient and reservoir temperatures of 25 °C and 80 °C, respectively. Dynamic viscosity of the crude oil was determined using a viscometer. Specific gravity of the crude was also determined using a hydrometer with ASTM D1298 -12b standard test method. The API gravity was determined using the expression in Eq 1:

$$API = [141.5/SG] - 131.5 \dots \dots \dots (1)$$

Where:

SG = Specific gravity

2.6. Rheological properties of polymer

The rheological properties of *Abelmoschus esculentus* such as viscosity and yield stress were determined using a rheometer. The effect of polymer concentration on its viscosity, the effect of shear rate and the effect of temperature on the viscosity of the natural polymer.

2.7. Phase behaviour analysis

To analyse the fluid compatibility, an aqueous stability test was performed between the natural polymer and the brine solution to determine the presence of cloudy solution and precipitates in the aqueous phase. This screening ensures polymer compatibility with the electrolyte concentration. The polymer-brine solutions were subjected to varied temperatures (30 °C, 50 °C, 80 °C and 100 °C) and visually inspected after 24hours. Cloudy samples containing solids such as precipitates were considered incompatible as only clear, cloudless fluids were selected.

Salinity scan was conducted to determine the salinity tolerance of the polymer at varying electrolyte concentration. Polymer concentration was kept constant, while brine salinity was varied, and corresponding pH value was determined using a pH meter. The experiment was conducted using a glass test tube each containing a total volume of 10 ml and later subjected to increased temperature of 50 °C and 100 °C to ensure its solubility.

2.8. Determination of Core sample properties

A cylindrical core which served as a porous media was obtained from a sandstone reservoir at a depth of 2.5 km with lithological properties ranging from fine, well-sorted, moderately cemented grains. The core sample was thoroughly cleaned using toluene and then dried. The weight of the core before saturation was determined. The length and diameter of the core was measured using a caliper and micrometer screw gauge. The core was subsequently saturated with brine in a vacuum timber for 24 hours and re-weighed afterwards. The pore volume was calculated as the ratio of the difference in weight of the saturated core and the dry core to the density of the brine (liquid saturation method). The bulk volume was determined using the expression in Eq 2. Effective porosity of the core was estimated manually using the saturation method as the ratio of pore volume to bulk volume, expressed in percentage.

$$V_b = \pi r^2 h \dots \dots \dots (2)$$

Where:

V_b = Bulk volume

r^2 = Radius of the core

h = Length of the core

2.9. Core flooding analysis

Oil displacement test was conducted with the sandstone core serving as the porous medium while the natural polymer solution served as the chemical recovery agent. A fabricated core flooding scheme was setup to conduct the oil displacement test at reservoir conditions of 80 °C and 8000 psi. Figure 4 shows the experimental set-up used as the displacement efficiency and recovery factor of the natural surfactant in both brines was calculated. The oil displacement test was conducted sequentially starting with the drainage process, imbibition, and polymer flooding.

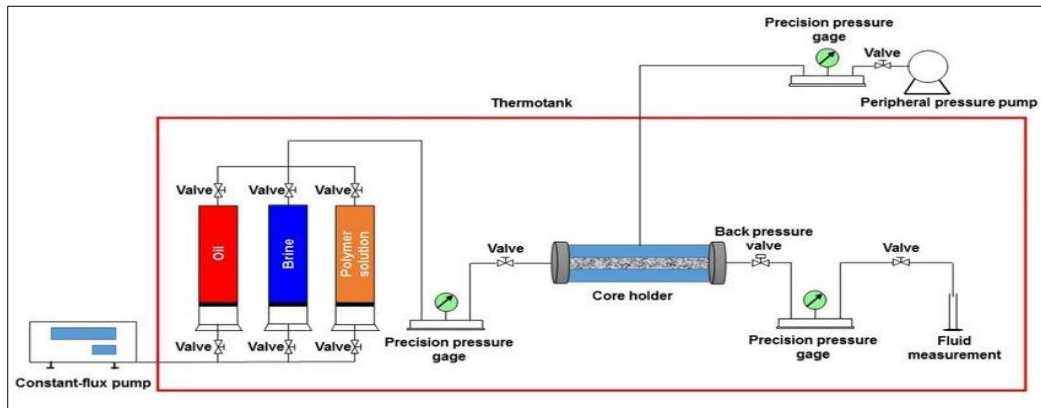


Figure 4 Schematic diagram of the core flooding experiment. [23]

2.9.1. Drainage

The migration and accumulation of the oil throughout the flow lines and in the core. The drainage process took place under constant flow rate until the oil occupied 100% of the pore spaces. The displaced brine was collected, and the volume recorded as the initial water saturation “ S_{wi} ” or OIIP.

2.9.2. Imbibition

To maintain reservoir pressure, 4 PV of brine was injected into the core to displace oil at a constant flow rate of 1 ml/min. The volume of displaced oil was collected and measured, and the residual oil saturation was calculated.

2.9.3. Enhanced oil recovery

Polymer flooding as a recovery mechanism was applied at this stage of the experiment where 2 PV natural polymer solution with a concentration of 5000 ppm was injected into the core at a constant flow rate of 0.4 ml/min to recover the additional residual oil that had been bypassed by the water flood process. This polymer concentration (5000 ppm) was selected in line with the findings of [18]. The flooding continued until an oil cut of less than 1% was recorded, thereafter, the oil sweep efficiency and additional recovery factor were determined.

2.10. Simulation analysis

A simulation model was built and validated with the laboratory results obtained at reservoir conditions of 8000 psi and 80°C using a 1D reservoir model. The reservoir model using Eclipse -100 simulation software was created based on the acquired laboratory data. Some of these data were measured while others were calculated laboratory data. To develop a Polymer flooding model in Eclipse 100 a complex range of correlations in form of keywords are needed to build the reservoir model.

2.10.1. Polymer flooding activation process

The model was activated under ‘RUNSPECS’. The keyword “brine” is only required if the salt-sensitive is required for polymer. The treatment of polymer viscosity is represented by Toold-Longstaff “TLMIXPAR” which is normally set at default (1) to enable mixture between parameters to occur. The keyword “PLYMAX”, defines the maximum polymer and salt concentration that is usually used in the effective fluid component viscosity. To define the viscosity of an integral mixed polymer solution “PLYVISC” need to be used. The treatment of polymer adsorption required the “PLYADS or ADSORP” plus the argument “POLYMER” under “PROPS” section. The proposed keyword enabled the polymer adsorption to become directly dependent on the salinity and the rock permeability. The rock mass density, dead pore volume and residual resistance factor is commonly represented by the keyword “PLYROCK” also under “PROPS”. Still in

“PROPS” section, non-Newtonian rheology was activated by setting “PLYSHEAR”. Alternatively, “HERSCHEL BUCKLEY” model could be used.

Under “REGION” section, “FIPNUM”, “SATNUM”, “EQLNUM” and “PVTNUM” were activated to determine the number of tables required for the fluid in place, fluid saturation, equilibrium region and the PVT data. Finally, under “SCHEDULE” section, the injection of polymer/salt concentration was represented by the keyword “WPOLYMER” enabling polymer flow in the reservoir.

3. Results and discussions

3.1. Crude oil characterization

The viscosity and API gravity of the crude oil was determined at ambient and reservoir temperatures as outlined in Table 3. The API values obtained at ambient and reservoir temperatures were 20.3 °and 22.2° respectively. This implies that it falls into the category of heavy crude as reported [24]. It was also observed that as temperature increased, the API value also increased. At 80 °C, a slight reduction in the density of crude oil was observed. The viscosity of the crude oil was greatly affected by the increase in temperature as reported by [25]. The viscosity of the heavy crude dropped from 92.6 mPa.s to 10.4 mPa.s as the temperature increased because of the decline in the force of cohesion between the oil molecules.

Table 3 Properties of Crude Oil Sample

Physical Properties	Values at 25 °C	Values at 80 °C
Specific gravity (g/m ³)	0.929	0.913
API (°)	20.3	22.2
Viscosity (mPa.s)	90.6	9.8
Asphaltene (wt.%)	0.77	
Colour	Brownish black	
pH value	6.2	

3.2. Results of Polymer Rheological properties

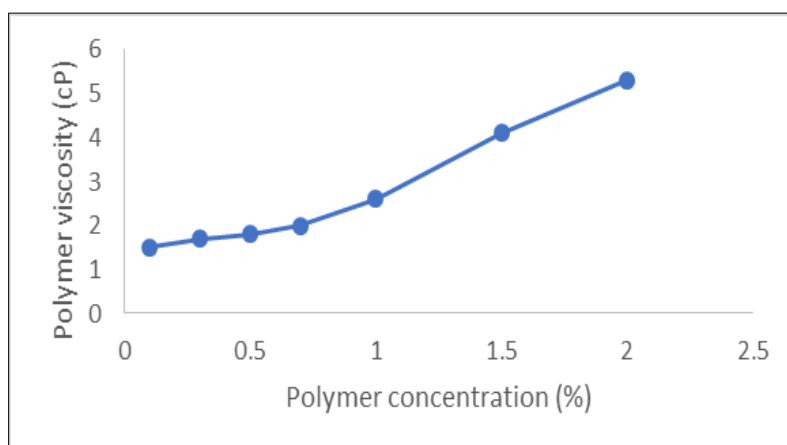


Figure 5 Polymer Concentration against Viscosity

The effect of polymer concentration on viscosity was studied at laboratory temperature. Fig. 5 shows a plot of polymer concentration against viscosity. The result shows that polymer concentration is directly proportional to the viscosity of the polymer solution, as polymer concentration increased in sync with polymer viscosity. To determine the effect of temperature, polymer concentration of 5000 ppm with a viscosity of 1.8 cP (see Fig 6) was subjected to varied temperatures. Results showed a gradual increase in the viscosity of the polymer-brine solution as the temperatures

increased (see Fig. 6). At reservoir temperature of 88 °C, *Abelmoschus esculentus* had a viscosity of 2.4 cP, indicating that the natural polymers are less susceptible to reservoir temperatures below 90 °C.

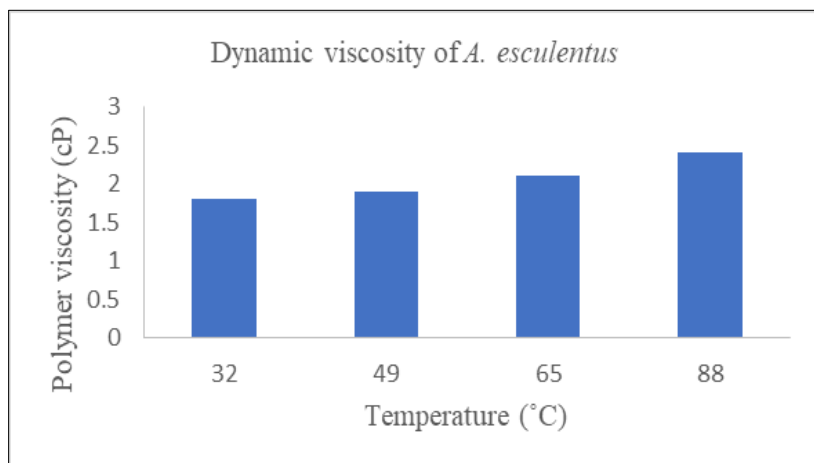


Figure 6 Polymer Viscosity as a function of Temperature

The effect of shear rate on the viscosity of the natural polymer at temperature values ranging from 32 °C to 88 °C was investigated. It was observed that as temperature increases and the RPM increases, the viscosity increased (see Fig. 7) indicating a shear thickening property. Furthermore, for most of the shear rates (06 – 0300), the viscosities remained constant. However, at reservoir temperature of 88 °C, the lowest viscosity values were recorded.

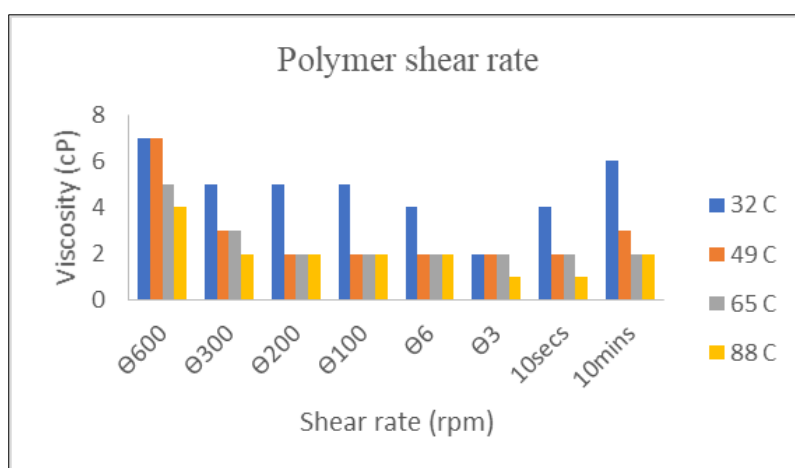


Figure 7 Effect of Shear rates on natural polymer Viscosity

3.3. Results of Polymer-Brine Phase Behaviour Analysis

Fluid compatibility test performed on the natural polymer solution and brine produced clear, cloudless, compatible solutions devoid of precipitates at reservoir temperature of 100 °C. At lower temperatures, less than 50 °C, it was observed that the polymer-brine solutions became slightly cloudy at higher polymer concentrations with little cellular debris settling at the base. However, at higher temperatures above 50 °C, the solutions became clearer and devoid of any debris over the range of concentrations.

3.4. Results of Salinity scan

The polymer concentration at 5000 ppm was kept constant while brine salinities from 0.5- 4.0 % was varied. Results showed a clear, compatible solution for all salinity range with a decrease in pH value (7.3 -6.3) as the salinity increases as seen in Fig. 8. The pH value of the polymer-brine solution indicates that at lower salinities, the polymer solution becomes more alkaline. However, due to the saponin content in *Abelmoschus esculentus* which indicates that it has some inherent surfactant properties, the pH value of 6 which corresponds to the brine salinity of 4.0% (40,000 ppm) was still considered appropriate.

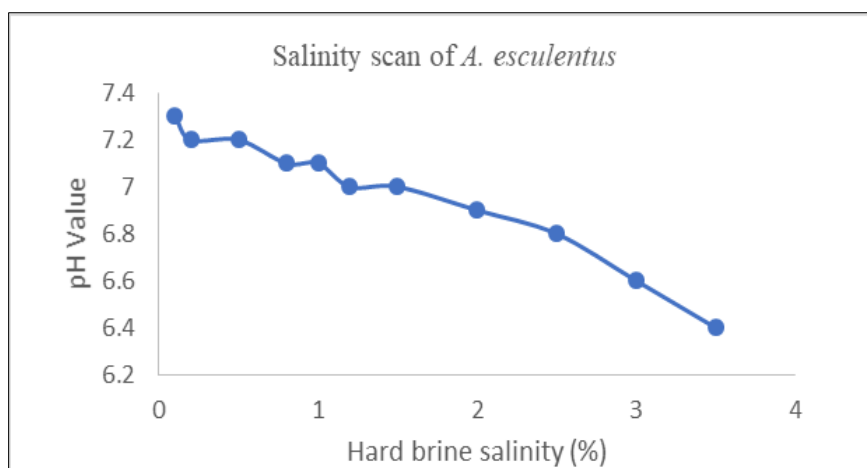


Figure 8 Salinity scan of *A. esculentus* and brine

3.5. Results of physical properties of Core sample

The mineralogical composition of the sandstone core obtained from the petrographic data of the well shows a 95% Quartz, 3% Kaolinite clay, 1% feldspar and minor amount of other clay minerals, a silica-based cement and a clay matrix. The depth at which the core sample was obtained ranged between 9000 – 11000 ft. at an initial reservoir pressure of 7500 psi and a reservoir temperature of 80 °C. The permeability of the core is 500 mD. The calculated properties of the sandstone core sample with a pore volume and porosity of 8.5 cm³ and 17.1 % respectively measured using the saturation method at ambient conditions are reported in Table 4. The obtained porosity value is typical of sandstones which have porosities ranging from 5 - 40% as reported by [26].

Table 4 Properties of Core Sample

Parameter	Value
Core length (cm)	10.1
Core diameter (cm)	2.5
Bulk volume (cm ³)	49.8
Dry sample mass (g)	99.2
Saturated sample mass (g)	107.9
Mass of brine (g)	8.7
Brine density (g/cm ³)	1.02
Pore volume (cm ³)	8.5
Porosity (%)	17.1

3.6. Results of Oil displacement Analysis

Polymer flooding experiment was performed using the natural polymer, *Abelmoschus esculentus* as the polymer agent at 5000 ppm concentration under reservoir temperature of 80 °C. The experiment commenced with heavy crude being used to displace brine from the brine saturated core. The values of irreducible water saturation and oil initially in place (OIIP) were calculated as presented in Table 5. Formulated brine containing divalent ions at 4.0% salinity was injected into the core to displace oil at an injection flow rate of 1.0 ml/min. An oil recovery of 40.65% was attained after secondary flooding at reservoir temperatures. Polymer flooding was injected into the core to recover residual oil left behind after brine flooding due to capillary forces. 2PV of the polymer agent was injected at a flow rate of 1.0 ml/min for about 2 hrs. and 10 mins. At an oil cut of less than 1% with negligible oil production, the experiment was terminated and the incremental oil recovery. An additional recovery factor of 16.26 % OIIP and a displacement efficiency of 27.4 % (see Table 5) was achieved. In their experimental study, Obuebite *et al.* [18] had reported that 0.5%wt Okro in brine devoid of divalent ions (soft brine) and brine containing divalent ions (hard brine) gave an additional recovery of 26.3%

OOIP and 23.4% OOIP respectively after waterflooding. A lower recovery factor of 16.26 % obtained in this study could be attributed to the higher viscous crude oil and the reduced porosity of the core plug used. This implies that a viscosity enhancer is needed to further increase the viscosity of the natural polymer agent. Finally, a chase water flooding was conducted, where the brine was injected into the core again to push any polymer solution and in turn recover more residual oil. An additional recovery of 13.55 % OIIP was obtained. Based on the experimental results obtained, the use of natural polymer, *Abelmoschus esculentus* showed a significant effect in recovering heavy oil at reservoir temperature and in the presence of divalent ions.

Table 5 Results of Core flooding Analysis

Parameter	Value
Pore volume (cm ³)	8.59
Irreducible water saturation at maximum oil saturation (cm ³)	1.21
Oil initially in place (ml)	7.38
Volume of crude recovered after imbibition (ml)	3.00
Volume of residual crude oil (cm ³)	4.38
Displacement efficiency after imbibition (%)	40.65
Residual oil saturation (Sor) (%)	59.35
Volume of oil recovered after polymer flooding (ml)	1.21
Additional recovery after polymer flooding (%)	16.26
Polymer Displacement efficiency (%)	27.40
Additional recovery after chase water flooding (%)	13.55

3.7. Results of Simulation Analysis

Table 6 Description of Simulated Model

Model	Description	Units
Grid Geometry	Cartesian	
Grid Dimensions Nx*Ny*Nz	10*1*1	
Cell Sizes Dx*Dy*Dz	0.58*3.37*3.37	Cm
Porosity	17.1	%
Permeability	500	mD

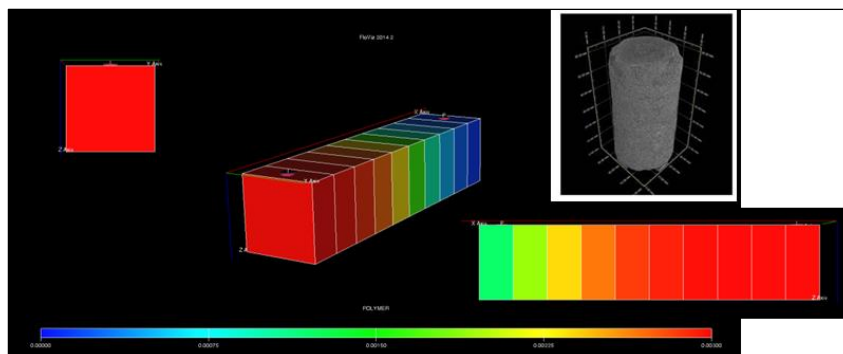


Figure 9 Constructed Grid Model

The Polymer simulation was carried out using ECLIPSE simulation software with the aim of replicating the polymer-brine model obtained from the laboratory. The simulated model was built using the model description outlined in Table 6. A figure showing the grid model constructed is seen in Fig. 9. The simulation results obtained from the reservoir simulation analysis are presented. The analyses and discussions are stated under each simulation model plot.

3.7.1. Waterflooding recovery factor “RF” – Laboratory & Simulation

The total recovery factor obtained for both secondary flooding (40.65%) and chase brine flooding (13.55%) within a total recovery period of 90 minutes was 54%. The recorded values obtained from the laboratory core flooding test was used to plot a graph of Recovery factor over Time as shown in Fig. 10 where both shows a substantial increase in recovery factor.

A plot of Recovery factor as a function of time was obtained from the simulation model as shown in Fig. 11. The total recovery factor as seen in the simulation model was about 53% OIIP.

The laboratory and simulation model were successfully matched together as shown in Fig.12, where the total recovery factor of 54% over a total oil production of 90 minutes in both cases (laboratory and simulation model) was achieved.

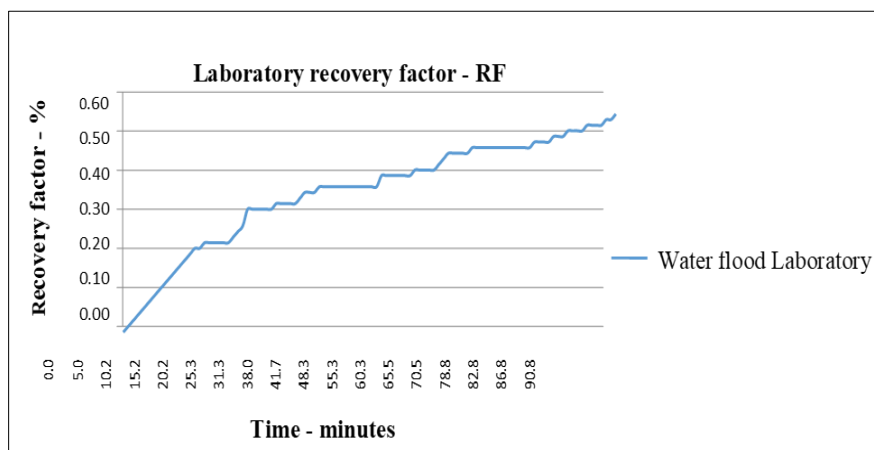


Figure 10 Recovery factor results from the core flood experiment

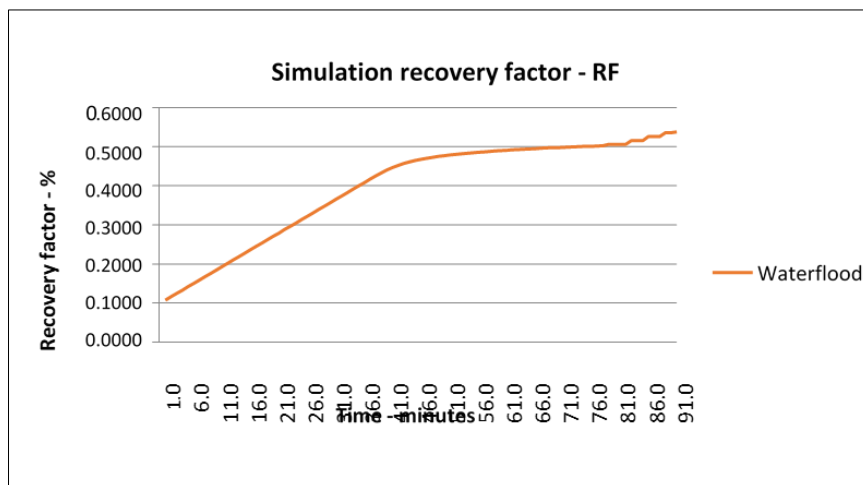


Figure 11 Recovery factor results from Eclipse – 100

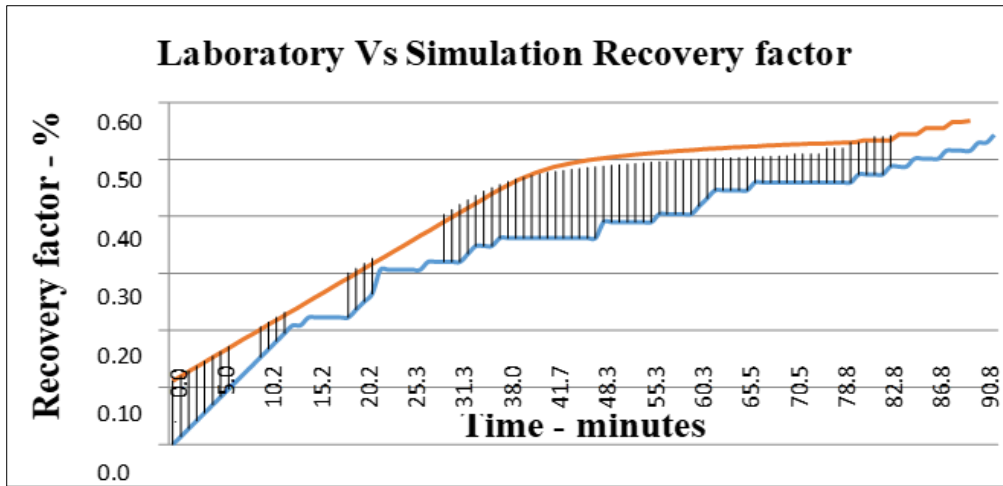


Figure 12 Matching of Laboratory and Simulation models

3.7.2. Polymer flooding recovery factor “RF” – Laboratory & Simulation

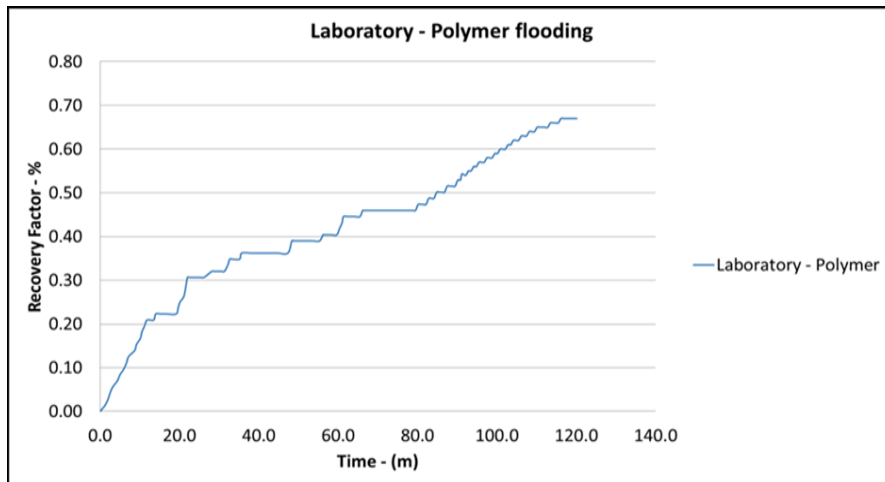


Figure 13 Additional recovery from Polymer flooding – Laboratory

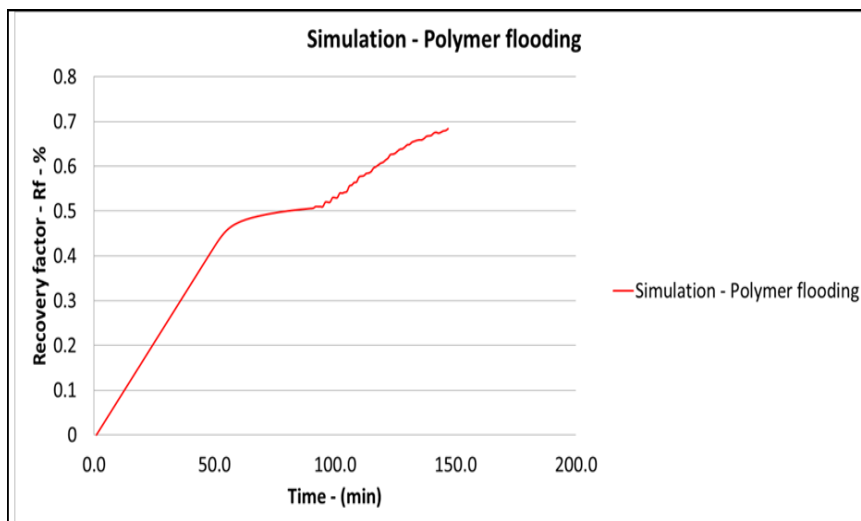


Figure 14 Additional recovery from Polymer flooding – Simulation

Polymer flooding as an enhanced oil recovery method began as oil production had reached its limit using secondary recovery mechanism (Waterflood). 2PV of polymer was subsequently injected into the core to recover the remaining oil left behind by waterflooding and an additional oil recovery of 16.26% was obtained after 130 minutes of production time. Figs. 13 and 14 shows the laboratory and simulation recovery factor trend. To match the additional oil recovery obtained from the core flooding, the recorded data was correlated and generated into a reservoir simulation model with data from both models being closely related.

3.7.3. Polymer flooding – Recovery factor matching process

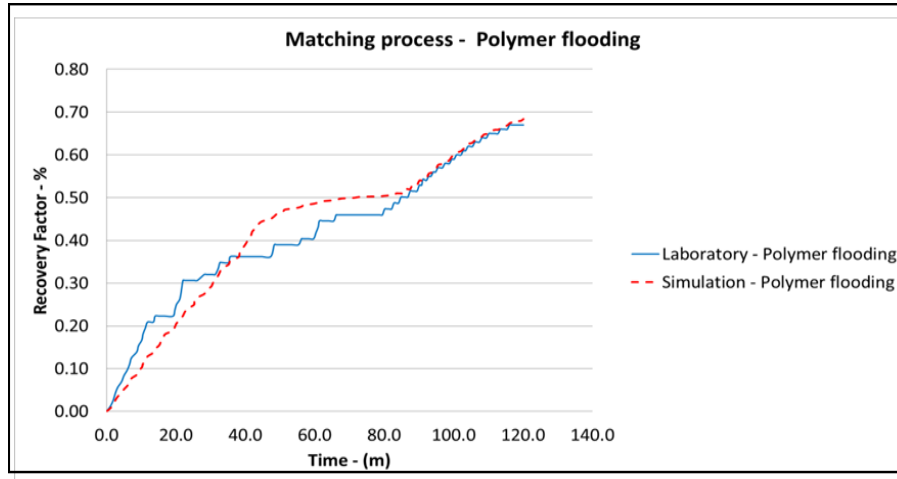


Figure 15 Matching process in Polymer flooding - Laboratory & Simulation

By plotting both results it could be observed that the polymer flooding recovery factor from laboratory and simulation was successfully achieved. As shown in Fig. 15, the waterflooding recovery factor showed to be 54% and the additional recovery factor of 16.26% when polymer was injected giving a total recovery factor of about 70%. In this case, the level of uncertainties was 1% as can be observed from the results.

4. Conclusion

The capabilities of a natural polymer obtained from *Abelmoschus esculentus* plant were experimentally investigated to determine its efficiency in displacing heavy oil in a high temperature, high salinity reservoir. Based on the outcome of this study, it was observed that *Abelmoschus esculentus* is water-soluble and solubility increased as temperature increased. The rheological analysis showed that certain factors must be considered but critical amongst them is the polymer viscosity reservoir salinity, presence of divalent ions, reservoir temperature, oil composition and polymer concentration. Phase behaviour studies showed high compatibility of the natural polymer (*Abelmoschus esculentus*) in high salinity brine solution and the polymer is highly tolerant of divalent ions (Ca^{2+} and Mg^{2+}) even under reservoir conditions of 100 °C. Results showed a gradual increase in the viscosity of the polymer-brine solution as the concentration and temperatures increased. Results from core flooding analysis at reservoir temperature of 80 °C indicate that *Abelmoschus esculentus* recovered additional oil in the presence of divalent ions with a recovery factor and displacement efficiency of 16.26 % OIIP and 27.4% respectively, which implies that the natural polymer agent can increase the sweep efficiency of heavy oil. The total recovery factor (RF) for polymer flooding and brine flooding was successfully achieved at about 70% OIIP. The simulation model was built to replicate the laboratory model. The recovery factor (RF) history matching between laboratory and simulation model was successfully achieved. *Abelmoschus esculentus* has a great potential to be used as a polymer agent for chemical enhanced oil recovery process. However, extraction and modification of the natural polymer is recommended to enhance its viscosity. The chemical stability (rate of degradation) of the natural polymer, *Abelmoschus esculentus* with the injected brine over a period needs to be ascertained. Further simulation analysis is recommended to produce a more accurate, upscaled model to apply on field pilot studies.

Compliance with ethical standards

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Disclosure of conflict of interest

The authors declare that they have no competing interest.

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