An Experimental Study of Polymer Flooding to Enhance Oil Recovery

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An Experimental Study of Polymer Flooding to Enhance Oil Recovery

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Abstract— Experimental investigation of the impact of a synthetic polymer used to enhance oil recovery in an Egyptian oilfield was the goal of the current study. According to the findings of the current study, polymer solutions display non-Newtonian flow behavior under a variety of temperature, salinity, and shear rate conditions. The shear rate, salt level, temperature, and solution concentration all affect the apparent viscosities of polymer solutions. Studying how salinity and temperature affect how polymer solutions of various concentrations flow through porous media revealed that, up to a certain point, the mobility of the solutions increases with the flow rate, after which the mobility decreases with the flow rate. The mobility as a function of water saturation showed that during the tertiary recovery stage as compared to that during the secondary recovery stage, both the water mobility and the total mobility greatly reduced, and the oil mobility somewhat rose. The mobility analysis suggested that motion might be important in understanding how these processes increase oil recovery.

Keywords—Polymer EOR, polymer flooding, mobility ratio and Polymer Solution in porous media.

I. INTRODUCTION

While the number of conventional oilfield discoveries is decreasing, the demand for oil is predicted to grow by about 1.5% year. After the primary measures have been exhausted, water flooding is a popular and efficient strategy for secondary recovery. Many sandstone or carbonate reservoirs have poor sweep efficiency as a result of bypassed or unswept oil, which results in low primary and waterflooding recovery. 50-70% of the oil in the formation is typically still present after water flooding, and oil cannot be extracted further without the use of chemical, thermal, or gas injection procedures [1]. It is acknowledged that conventional oil reserves are limited and that finding new oil fields is becoming more expensive. These trends offer extra motivation for improved recuperation techniques.

Up until the 2000s, chemical flooding was a less popular EOR technique than thermal and gas flooding, but recently sizable projects have been started or resumed. The literature has reported many instances of technically successful polymer and surfactant-polymer field initiatives [1]. The most crucial EOR method for raising the water-to-oil mobility ratio is polymer flooding. The polymers work to make the injected water more viscous and the swept zone less permeable, enhancing the vertical and areal sweep efficiency of the water injection and, as a result, the oil recovery [2].

The polymer flooding technology has been suggested as far back as the early 1960's as an oil recovery/displacement process applied in the enhanced oil recovery phase where its main purpose was to viscosity the displacing fluid that is water in order to improve residual oil recovery [3].

Over traditional water flooding methods, polymer flooding has a greater economic potential because it increases the efficiency of oil recovery through two main mechanisms: 1) by reducing water mobility, and 2) by selectively altering the permeability to water. A polymer flood may increase the effectiveness of the oil recovery process in three different ways [4]:1) By altering fractional flow due to the actions of polymers, 2) By lowering the water/oil mobility ratio, and 3) By diverting injected water from swept zones.

The polymer flooding procedure is most successfully used early in a water flooding project, when mobile oil saturation is still high, according to laboratory and field applications [5-7]. The viscosity of the flowing fluids can be changed to change the Mobility ratio. When the standard method is unattractive, enhanced oil recovery techniques are used to increase reservoir recovery. In order to reduce the mobility of injected water, polymer flooding requires the injection of a polymer.

By using this method, the reservoir sweep is improved and less injection fluid is needed to retrieve a given amount of oil. The injection water was given a small amount of polymer to add, which made the fluid viscous. The flow of polymer solutions through porous media makes it impossible to differentiate between a change in solution viscosity and a decrease in rock permeability for non-Newtonian fluids due to the viscosity fluctuation with shear rate. The combined ratio

(k/) has been a popular measure in recent years for describing the flow characteristics of a specific polymer solution-porous system. The permeability and viscosity of the polymer solution, k and, are used to define the mobility () of the solution as (k/) p. An rise in water viscosity and a decrease in relative permeability cause mobility control in the polymer solution.

Calculations involving mobility and mobility ratio are crucial for establishing the desired apparent viscosity of the injection fluid. These were based on the calculated relative permeability and viscosity. Therefore, the mobility may be calculated after the permeability at each site. Mobility ratios below one are seen to be good for displacement, whereas ratios above one are thought to be unfavorable. Since water and oil have different relative permeabilities, a water viscosity greater than the oil viscosity is required to achieve a mobility ratio that is advantageous for displacement.

II. METHODOLOGY

A. EXPERIMENTAL WORK

- Crude oil samples were obtained from an Egyptian oil field with a multilayer-producing zone located in the Gulf of Suez.
- 2) Synthetic formation brine is typically used to initially saturate the sandpack model and seawater injected during water flooding experiments. This formation brine is similar in composition to the actual reservoir brine obtained from the same oilfield.
- **3)** The polymer used in this study was a high-molecular-weight hydrolyzed polyacrylamide (Alcoflood 1275A) polymer from Allied Colloids.
- 4) A Brookfield digital viscometer was used in this study to measure the shear rate versus viscosity of the polymer solutions (Brookfield digital Model DV-III+ No. M/98-211-A0701, rotating spindle-type coaxial cylinder viscometer).
- 5) The sand packs used in this study had an average porosity of 21 % and an average permeability of approximately 800 md.

B. FLOW OF POLYMER SOLUTION IN POROUS MEDIA

The experimental procedures used to investigate the rheological behavior of the tested polymer solutions in porous media are schematically shown in Fig. 1. This principle can be summarized as follows:

- The model was packed with sand and completely evacuated from the air using a vacuum pump. Evacuation proceeded until the manometer was stabilized for approximately 4 h.
- 2) The sand pack was then saturated with brine, with salinity equal to that of the investigated polymer solution. Brine

volume was used to determine the pore volume of the model, and the porosity of the sand pack was calculated.

- 3) Brine is circulated through the model by applying pressure, and the absolute permeability is determined by Darcy's equation. At least 20 P.V. of the polymer solution was injected into the model to ensure the adsorption of the polymer.
- 4) When the pressure drop through the model was about constant, steady-state flow was attained. A new point should be obtained by altering the injection rate after reaching a steady state.
- 5) The model was then cleaned and repacked with a clean sand mixture for the next experimental run.

C. OIL DISPLACEMENT TESTS

A series of tests were performed under different conditions to study the effect of polymer solutions on oil displacement. A uniform sand pack was used for the displacement tests. The temperature of the test was adjusted to 50 °C, 70, and 90 °C. The sand pack was evacuated and then saturated with water with the same salinity components as the field formation water (8%, 10%, and 12%). The absolute permeability was obtained by circulating formation water through the sandpack by applying pressure and measuring the flow rate of water at a certain pressure drop across the sandpack. Subsequently, the permeability and relative permeability were determined. The sand pack was then saturated with crude oil by the continuous injection of oil until no water was recovered. At this point, the initial water saturation (Swi) can be determined. The first oil saturation following the oil flood is therefore the ratio of recovered water to total pore volume. At this time, it was assumed that the flow was single-phase, steady-state, and under constant pressure. Given these presumptions, the oil permeability (end-point oil permeability) at initial water saturation was calculated using the Darcy equation. The liquids produced were collected continuously and the amounts of oil and water were determined. To establish residual oil saturation, the sand pack was injected again with seawater (40,000 ppm) until no more oil was produced. The model is now at residual oil saturation, using the same assumptions as with oil, and calculates the water phase permeability (end-point water permeability), Kw, at residual oil saturation. The sand pack was then flooded with a polymer or surfactant solution, followed by brine, until residual oil saturation was reached. By raising the temperature, salinity, and concentration of the polymer solution, the polymer injection technique was repeated. For the subsequent trial run, the sand pack was cleaned and repacked with a clean sand combination.

III. RESULTS OF LAPORATORY INVESTIGATION

A. CHARACTERIZATION OF POLYMER SOLUTIONS THROUGH RHEOLOGICAL BEHAVIOR

Polymer remedy Rheology is essential for assessing and constructing a polymer flood, and when sufficiently high shear rates are applied, the viscosity of polymer solutions employed in polymer waterflooding typically exhibits shear-thinning behavior. For a shear-thinning fluid, the apparent viscosity of the fluid decreases as the fluid experiences an increasing shear rate. The viscosity vs shear rate for the four polymer solutions is displayed in Figures 3-8. The figures demonstrate a crucial factor for enhancing the mobility ratio between oil and water: the apparent viscosity of the solutions lowers as the shear rate rises. The efficiency of the polymer flooding improved as the injection viscosity rose. Numerous things can influence viscosity. The solution viscosity first rose with increasing polymer molecular weight for a particular set of conditions. Second, higher viscosity and higher sweep efficiency are produced by an increased polymer concentration. Third, as the temperature increased, the viscosity of the solution decreased. Fourth, the increased salinity and hardness in the reservoir water also decreased the solution viscosity for anionic polymers.

At most reservoir flow conditions, polymer solutions employed in polymer flooding are shear-thinning. As a result, it is necessary to measure solution viscosities as a function of shear rate [9]. Rheological properties become an important factor with high injection rates or high-viscosity fluids. In general, polymer solutions exhibit non-Newtonian, pseudo-plastic, shear-thinning behavior, i.e., when it flows, its viscosity will be changed, and higher flowing velocity leads to lower viscosity due to an increase in the shear rate. The rheological measurements have been made to characterize the apparent viscosity of polymer solution as a function of shear rate, polymer concentration, polymer molecular weight, degree of hydrolysis, salinity, hardness, and temperature. As evidenced by Figs. 3 through 8, polymer solutions exhibit non-Newtonian behavior in the range of the investigated rates. Figs. 3 through 8 indicate that the viscosity of polymer solution decreases with increasing shear rate. The decrease in polymer solutions viscosity with increasing shear rate is due to the alignment and deformation of the polymer molecules.

Viscous forces acting on the solutions are stronger than electrostatic interactions between the particles, which is why viscosity decreases as shear rate rises. The polymer chains are thus oriented in the direction of flow at high shear rates, which causes a viscosity drop or shear-thinning characteristic [10]. The association phenomenon, which raises the hydrodynamic volume of the polymer chains, may be to blame for the rise in apparent viscosity. The apparent viscosity rises with increasing polymer concentrations for all shear rates, with higher concentrations showing a stronger dependence on the shearrate. Both of these outcomes are expected given that the number of polymer molecules in solution increases with polymer concentration, increasing the likelihood of particle entanglement or cross-linking. According to Fig. 9, viscosity reduces as temperature rises. A polymer needs to be stable under reservoir conditions in order to be useful in EOR applications. With the same polymer concentration, Figs. 9 through 11 demonstrate how polymers are sensitive to temperature. From 50 °C to 70 °C, the viscosity of polymer solutions decreased. This might be as a result of the fact that when temperature rises, molecular motion increases. Additionally, it is evident from the results above that shear rate reduces as temperature rises.

Brine is typically found in oil reservoirs as formation water. Its sensitivity to salt concentration is one of the most prevalent drawbacks of the polymer solution to be used for enhanced oil recovery. The size of the polymer molecules in solution reduces as the salt concentration rises, which also affects viscosity. The examined polymer solution's viscosity is shown to decrease as salinity concentration rises in Fig. 9. As seen in Figs. 9 through 11, viscosity behavior at low salinity differs significantly from that at higher levels for lower polymer concentrations. The size of the polymer molecules in solution reduces as the salt concentration rises, which also affects viscosity. The negatively charged hydrolyzed carboxylate groups on the polymer backbone are less electrostatically attracted to one another thanks to the cations of the dissolved salts. In order to accomplish this, cations screen and collapse the locally produced, negatively charged double layer that surrounds the carboxylate species. With rising salt concentrations, and even at fixed salt concentrations, with increasing charge of the salt cations, the degree of collapse of the negatively charged electrostatic fields surrounding the carboxylate groups of the polymer increases. The electrostatic repulsive forces that encourage polymer backbone-chain distension are reduced as the electrostatic fields surrounding the carboxylate groups of the polymer collapse. This leads to a substantial reduction in polymer-solution viscosity. From Figs. 9 and 10, it can be seen that the viscosity of the polymer solution increases with polymer concentration at 50 and 70 oC.

Physically, fewer polymer molecules will be present in the solution and will be farther apart when the concentration of polymer is low. The likelihood of the cross-linked process occurring in various molecules' chains is increased. The distances between the molecules are shorter when the concentration of polymers is larger [11]. Practically speaking, the viscosity of the injected solution is increased by the addition of a high-molecular-weight polymer. To counteract the rise in aqueous relative permeability, this increase in viscosity is required. By reducing unstable displacement (fingering),

channeling brought on by layering, and other heterogeneities, higher viscosity (low mobility ratio) also improves sweep efficiency in reservoirs. Reservoir permeability and other rock properties, such as pore structure, can be used to determine the length of the polymer structure, but in general, lower permeability necessitates the use of a lower molecular weight polymer. He negatively charged the hydrolyzed carboxylate groups on the polymer backbone. Cations do this by screening and collapsing the local negatively charged double layer formed around the carboxylate species. The degree of collapse of the negatively charged electrostatic fields surrounding the polymer's carboxylate groups increases with increasing salt concentrations, and at constant salt concentrations, with increasing charge of the cations of the salt. As the electrostatic fields surrounding the polymer's carboxylate groups collapse, the electrostatic repulsive forces that promote polymer backbone-chain distension decrease. This leads to a substantial reduction in polymer-solution viscosity. From Fig. 9, it can be seen that the viscosity of the polymer solution increases with polymer concentration at 50 and 70 oC.

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B. TRANSPORT CHARACTERIZATION OF POLYMER Solutions in Porous Media

The geometry of the matrix influences wall-bounded flows of fluids. This influence is emphasized particularly for flowing high-molecular-weight polymer solutions due to the occurrence of flow regions with elongation gradients frequently encountered in flow patterns through porous media. In such cases, a drastic increase in flow resistance is experienced, while in the more familiar shear flow, the same polymer solutions do not exhibit any unusual phenomena. This unconventional flow behavior must thus be ascribable to varying motions and deformations of dissolved macromolecules in shear flow and elongational flow.

After achieving steady state, a wide variety of pressures were used to assess the mobility of the polymer solution. A succession of polymer solutions with progressively higher pressure, temperature, salinity, and concentration were injected into the polymer matrix.

As evidenced by Figs. 12 through 14, the critical flow rate Q* (the flow rate above which the viscoelastic flow pattern prevails) decreases with increasing concentration up to 2000 ppm polymer solutions. This is attributed to the rise in solution viscosity and to the reduced values of the flushed permeability as a consequence of the adsorption of polymer molecules by the sand grains. The ultimate rise in Q* value for higher polymer concentrations up to 2000 ppm may be attributed to the associative movement of the polymer molecules and the solvent molecules as a bulk caused by stronger polymer-polymer and polymer solvent interactions [12]. At flow rates lower than Q*, the slope is less than unity, which is an indication of viscous flow. At flow rates higher than Q*, the slope is larger than unity, which corresponds to a viscoelastic character. It is noticed that the value of Q* decreases as the concentration of the polymer increases from 500 to 2000 ppm. It is impossible to discern between a change in the solution viscosity and a decrease in the rock permeability for non-Newtonian fluids due to the viscosity fluctuation with shear rate and the flow of polymer solutions through porous media. The combined ratio (k/) has been widely employed as a single measure in recent references to characterize the flow characteristics of a specific polymer solution-porous system.

Figs. 12 through 14 indicate that the mobility of polymer solutions increases with flow rate until the point where the mobility reaches its maximum value. Beyond this point, mobility decreases with a further increase in the flow rate. This reduction in λ with flow rate is attributed to a dilatant's flow character in polymer solutions in this domain [12]. High-MW polymers that are flexible and coil-shaped, such as HPAM, can enter extensional and elongational flows when subjected to extremely high flow rates and shear fields. At this point, the apparent viscosity of the polymer solution can increase significantly. The polymer frequently suffers from mechanical shear degradation in this flow regime. Extensional flow of appreciable importance is only seldom expected to occur in solutions of well-designed polymer floods at the very nearwellbore zone next to the injection or production well.

As shown in Fig. 14, previously described, the effect of the addition of salt to polymer solutions consists of a reduction in the size of the polymer molecules. This leads to a loss of the viscoelasticity of the polymer molecules and an increase in the proportion of accessible spacewise pores in the polymer

molecules. The decrease in Q* that is experienced when the salt concentration rises may be due to increased polymer-sand interaction and decreased polymer-polymer interaction, coupled with a reduction in polymer-solvent interaction, leading to an increase in the value of the permeability.

C. THE ROLE OF INFORMATION TECHNOLOGY IN PROMOTING SUSTAINABILITY

The main accepted mechanism of mobilizing residual oil after water flooding is that there must be a rather large viscous force perpendicular to the oil-wet interface; this force must overcome the capillary forces retaining the residual oil, move it, and mobilize it. Polymer flooding has been thought to improve the mobility ratio and macroscopically increase the sweep efficiency. Three different concentrations of polymer solution in 4% seawater brine were used through these displacements at 50 °C, 70 °C, and 90 °C. Figs. 15 through 18 indicate that the higher the concentration of polymer, the more oil can be recovered (i.e., the displacement efficiency increased as the viscosity of the displacing fluid increased). It is seen from the results above that the oil recovery by polymer flooding increases more than that by conventional water flooding. The increment in oil recovery obtained for polymer flooding as compared to conventional water flooding at any concentration can be attributed to the improved mobility ratio of the system. An increase in the concentration of the polymer solution from 500 to 1500 ppm decreases the mobility of the polymer solution, as evidenced by the mobility versus flow rate curves.

In actuality, there are practical limits to how much polymer solutions may be concentrated. If the injection rate is held constant, the viscosity will significantly increase with an increase in polymer concentration, which will cause an increase in injecting pressure. The reservoir rock will fracture with excessive pressure.

Several experiments were conducted to explain the effects of temperature variation, which corresponds to the reservoir temperature. In general, temperature plays an important role in polymer flooding; it affects to a great extent the viscosity of oil or fluids in the porous medium. From Fig. 19, it can be seen that the higher increase in oil recovery was found when the temperature increased from 50 to 90°C (decreasing in oil viscosity). Also, in this study, it can be seen that at high temperatures (low viscosity), the oil recovery at breakthrough was higher than at low temperatures (high viscosity). The oil recovery factors of these flooding tests are about the same. So, the oil recovery efficiency under this condition depends mostly on the temperature. The temperature plays the most important part in the recovery efficiency because the oil recovery factors of these three concentrations are almost the same.

D. MOBILITY CONCEPTS APPLIED TO DISPLACEMENT PROCESS

The mobility ratio, which controls both the displacement and the volumetric sweep effectiveness of the oil displacement process, is a crucial element in all recovery productions. Because of mobility control, polymer flooding, as opposed to ordinary water flooding, can dramatically boost oil recovery in some reservoirs. A series of experiments have been conducted using different polymer solution concentrations. The results are plotted in Figs. 20 through 23. From these figures, it can be seen that the relative mobility of oil is slightly affected. On the other hand, the relative mobility of water significantly decreases as the polymer solutions are used compared with conventional waterflooding. The increased viscosity of the solution, as well as the polymer's adsorption and mechanical entrapment in the porous medium, were all thought to be the causes of the polymer solution's decreased mobility. The data from displacement tests are used to determine relative permeability and mobility ratios using Welge's, Miller's, and Khairy's techniques [14-17]. Their methods are based on the following equations:

fo = 1 / [(krd /k	ro) $(\mu o / \mu d) + 1)$]	(4-1)
Swav = Sw2 +	fo Qwi	
kro = fo / [d(1/e)]	Qwi Ir) / d(1/Qwi)](4-3)
$\lambda ro = Kro/\mu o$	and $\lambda rw = Krw$	v /µw(4-4)

A series experiments has been conducted using different polymer solution concentration Where S_{wav} is the average water saturation in the sandpack model, S_{w2} the water saturation at the out let face w_i is the total amount of fluid injected in pore volume and I_r is the injectivity ratio, λ_{ro} and λ_{rw} are the oil and water relative mobility. The procedure of this technique is explained in Appendix A.

IV. CONCLUSIONS

The following conclusions can be drawn from the present study:

• For the partially hydrolyzed polyacrylamide alcoflood 1275A solution used in this research, the viscosity of this solution increases with increasing polymer concentration. It decreases with increasing shear rate, salinity, and temperature.

• The mobility of polyacrylamide solutions in porous media decreases with increasing polymer concentration.

• Oil recovery is higher when polymer solutions are used compared with water flooding tests due to an improvement in the mobility ratio.

• The oil recovery increases with polymer solution concentration. However, in fact, only an ideal polymer concentration may be advised in order to maintain a high enough injection rate of polymer solution and prevent fracturing reservoir rock. • Oil recovery increases with increasing temperatures.

• The mobility of polymer solution through porous media decreases as the polymer concentration increases, with other variables remaining constant.

• The mobility of polymer solutions through porous media increases as flow rate increases until a point, the critical flow rate Q*, where the mobility reaches its maximum value. Beyond this point, mobility decreases as the flow rate increases.

Q*, decreases as polymer concentration increases.

Q*, decreases as salinity increases.

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VIII. FIGURES LIST

Figure 1 Schematic Diagram of the Flow Experiment



1- Compressed air 2- Brine reservoir 3- Polymer solution 4- Gage pressure 5- U tube mercury manometer 6- Sand pack model 7- Vacuum pump 8- Graduated cylinder

Figure 2 Schematic Presentation of Experimental Apparatus used in oil Displacement.





5- Polymer solution 6- Pressure gage 7- Mercury manometer 8- Displacement model 9- Opening for circulating water

10- Vacuum pump 11- Graduated cylinder



Fig. 3: Viscosity versus shear rate of different polymer concentrations in fresh water at 50°C.



Fig. 4: Viscosity versus.shear rate for different polymer concentrations in fresh water at 70°C.







Fig. 6: Viscosity versus shear rate of different polymer oncentrations in 30,000 ppm sea water brine at 70° C.



Fig. 7: Viscosity versus shear rate for different polymer concentrations in 40,000 ppm sea water brine at 50° C.



Fig. 10: Effect of polymer concentration on viscosity of polymer solution with different salinities at 50° C.













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Fig. 20: Effect of 0.25 p.v. slug of 500 ppm polymer concentration in 40,000 ppm sea water brine on water mobility during tertiary recovery stage as compared its mobility during secondary recovery by water flooding at 50° C.



Fig. 21: Effect of 0.25 p.v. slug of 500 ppm polymer concentration in 40,000 ppm sea water brine on water and oil mobilities during tertiary recovery stage compared with their mobilities during secondary recovery by waterflooding at 50° C.



Fig. 22: Effect of 0.25 p.v. slug of 500 ppm polymer concentration in 40,000 ppm sea water brine on water,oil, and total mobilities during tertiary recovery stage compared with their mobilities during secondary recovery by waterflooding at 50° C.



Fig. 23: Effect of polymer concentration solution in 40,000 ppm sea water brine on total mobility during tertiary recovery stage compared with their mobilities during secondary recovery by waterflooding at 70° c.

IX. APPENDIX A

In an effort to take into consideration the simultaneous flow of many phases while still allowing for single phase fluid flow through porous surfaces, the idea of relative permeability attempts to extend Darcy's law. Measurements of the relative permeabilities of oil and water are frequently made using the unsteady-state (USS) displacement in reservoir cores. Under unsteady-state systems, the laboratory displacement method for determining relative permeability can be used. The idea of relative permeability is an attempt to expand on Darcy's rule for fluid flow through porous media in a single phase to account for the simultaneous flow of multiple phases. Oil-water relative permeabilities are frequently determined using the unsteady-state (USS) displacement in reservoir cores. It is possible to use the laboratory displacement method for unsteady-state processes to measure relative permeability. Based on Welge [14] and Johnson et al. [19] methods, it is possible to determine relative permeability vs saturation curves from unsteady state displacement. The following equations form the foundation of the techniques:

$$f_{o} = \frac{1}{1 + \frac{k_{rv} \ \mu_{0}}{k_{ro} \ \mu_{w}}}$$
(A-1)

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$$f_o = \frac{dQ_o}{dQwi}$$
(A-2)

$$S_{wav} = S_{wi} + \frac{Q_o}{PV}$$
(A-3)

$$S_{w2} = S_{wav} - f_o \frac{Q_{wi}}{PV}$$
(A-4)

$$S_{w2} = S_{wi} + \frac{Q_o}{PV} - f_o \frac{Q_{wi}}{PV}$$
(A-5)
$$\frac{f_o}{k_{ro}} = \frac{d\left(\frac{1}{Q_{wi}I_r}\right)}{d\left(\frac{1}{Q_{wi}}\right)}$$
(A-6)

Where

Ir = (qt / Δ p) at any flood stage / (qt/ Δ p) at the start of injection

The technique derived from the above equations need to take two slopes of two plots at the same value of Qwi. Miller [15] presented the following equation that the best fit of the recovery data which, was proposed by MacAskill [20].

$$Q_o = a_o + a_1[ln(Q_{wi})] + a_2[ln(Q_{wi})]^2 + a_3[ln(Q_{wi})]^3 + \cdots.$$
(A-

Khairy, M proposed the following equation that best fit of the injectivity data:

$$\ln(\frac{1}{Q_{wi}I_r}) = b_o + b_1[\ln(\frac{1}{Q_{wi}})] + b_2[\ln(\frac{1}{Q_{wi}})]^2 + b_3[\ln(\frac{1}{Q_{wi}})]^3 \dots$$
(A-8)

Khairy arrived at the required two slopes by differentiating the equations (A-7) and (A-8). The derivative of equation (7) is given by equation (9).

$$\frac{dQ_{o}}{dQ_{wi}} = \frac{a_1}{Q_{wi}} + \frac{2a_2}{Q_{wi}}\ln(Q_{wi}) + \frac{3a_3}{Q_{wi}}\ln(Q_{wi})^2 + \dots$$
(A-9)

The derivative of equation (8) is given by equation (10) and arrived at using the following steps.

1- Equation (8) can be written as:

2- The derivative
$$\frac{d\left(\frac{1}{Q_{wl}I_r}\right)}{d\left(\frac{1}{Q_{wl}}\right)} \text{ is given by}$$
$$\frac{d\left(\frac{1}{Q_{wl}I_r}\right)}{d\left(\frac{1}{Q_{wl}}\right)} = \left[b_1Q_{wl} + 2b_2Q_{wl}Ln\left(\frac{1}{Q_{wl}}\right) + 3b_3Q_{wl}Ln\left(\frac{1}{Q_{wl}}\right)^2\right]^*$$
$$(Exp \left[b_o + b_1\left[\ln\left(\frac{1}{Q_{wl}}\right)\right] + b_2\left[\ln\left(\frac{1}{Q_{wl}}\right)\right]^2 + b_3\left[\ln\left(\frac{1}{Q_{wl}}\right)\right]^3\right)....$$
(A-10)

The calculations of the relative permeability and the relative mobility were performed using an Excel Spreadsheet constructed by Khairy, M. using the equations from (A-2) to (A-10).

The following steps are used to curve fit the experimental data and to determine both the relative permeability and relative mobility versus saturation curves using the constructed Excel Spreadsheet.

- Plot Qo vs. In Qwi and get the constants (a0, a1, a2,...) of the equation 1-(A-7).
- 2-Then determined the derivative of equation (A-9), and determine the value of the derivative (the slope of the curve) at the required \mathbf{Q}_{wi} using equation (A-9), which is f_{a} .

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- 3-Calculate injectivity, $Ir = (qt / \Delta p)$ at any flood stage / (qt/ Δp) at the start of injection
- 4-Plot ln(1/Qwi Ir) vs. ln(1/Qwi) and get the constants (b0, b1, b2,...) of the equation (A-8).
- $\frac{d\left(\frac{1}{Q_{wi}I_r}\right)}{d\left(\frac{1}{Q_r}\right)}$ 5-Then determined the derivative of equation (A-8),

and determine the value of the derivative (the slope of the curve) at the required \mathbf{Q}_{wi} using equation (A-10), which is m

- Calculate the average water saturation (S_{wav}) using equation (A-3). 6-
- 7-Calculate the water saturation at the outlet face (Sw2) using equation (A-4).
- Calculate the oil relative permeability using the following equation: $K_{ro} = f_o / m$
- Calculate the water relative permeability using the following 9equation:

$$k_{rw} = k_{ro} \frac{(1 - f_o)}{f_o} \frac{\mu_w}{\mu_o}$$

10- Oil and Water relative mobility λro and λrw are calculated using the following equations:

$$\lambda_{ro} = \frac{k_{ro}}{\mu_o}$$
 and $\lambda_{rw} = \frac{k_{rw}}{\mu_w}$

11- Then, plot $k_{\rm ro}$ and $k_{\rm rw}$ vs. $S_{\rm w2}$ curve.

12- Finally, plot λ ro and λ rw vs. Sw2 curve.

X. APPENDIX B

In an effort to take into consideration the simultaneous flow of many phases while still allowing for single phase fluid flow through porous surfaces, the idea of relative permeability attempts to extend Darcy's law. Measurements of the relative permeabilities of oil and water are frequently made using the unsteady-state (USS) displacement in reservoir cores. Under unsteady-state systems, the laboratory displacement method for determining relative permeability can be used. The idea of relative permeability is an attempt to expand on Darcy's rule for fluid flow through porous media in a single phase to account for the simultaneous flow of multiple phases. Oilwater relative permeabilities are frequently determined using the unsteadystate (USS) displacement in reservoir cores. It is possible to use the laboratory displacement method for unsteady-state processes to measure relative permeability. Based on Welge [14] and Johnson et al. [19] methods, it is possible to determine relative permeability vs saturation curves from unsteady state displacement. The following equations form the foundation of the techniques:

$$f_o = rac{1}{1+rac{k_{rw}\mu_o}{k_{ro}\mu_w}}$$

$$f_o = \frac{dQ_o}{dQwi}$$

$$S_{wav} = S_{wi} + \frac{Q_O}{PV}$$

$$S_{w2} = S_{wav} - f_o \frac{Q_{wi}}{PV}$$

(A-4)

(A-2)

(A-3)

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$$S_{w2} = S_{wi} + \frac{Q_o}{PV} - f_o \frac{Q_{wi}}{PV}$$

1

(A-5)

$$\frac{f_o}{k_{ro}} = \frac{d(\frac{1}{Q_{wi}I_r})}{d(\frac{1}{Q_{wi}})}$$

Where

(A-6) Ir = (qt / Δ p) at any flood stage / (qt/ Δp) at the start of injection

The technique derived from the above equations need to take two slopes of two plots at the same value of Qwi. Miller [15] presented the following equation that the best fit of the recovery data which, was proposed by MacAskill [20].

 $Q_o = a_o + a_1[ln(Q_{wi})] + a_2[ln(Q_{wi})]^2 + a_3[ln(Q_{wi})]^3 + \dots (A-7)$ $ln(\frac{1}{q_{wi}l_r}) = b_o + b_1[ln(\frac{1}{q_{wi}})] + b_2[ln(\frac{1}{q_{wi}})]^2 + b_3[ln(\frac{1}{q_{wi}})]^3 \dots (A-8)$ (A-8)

Khairy arrived at the required two slopes by differentiating the equations (A-7) and (A-8). The derivative of equation (7) is given by equation (9).

$$\frac{dQ_o}{dQ_{wi}} = \frac{a_1}{Q_{wi}} + \frac{2a_2}{Q_{wi}} \ln(Q_{wi}) + \frac{3a_3}{Q_{wi}} \ln(Q_{wi})^2$$

The derivative of equation (8) is given by equation (10) and arrived at using the following steps.

1-Equation (8) can be written as:

$$\frac{1}{Q_{wi}I_r} = Exp[b_o + b_1[ln(\frac{1}{Q_{wi}})] + b_2[ln(\frac{1}{Q_{wi}})]^2 + b_3[ln(\frac{1}{Q_{wi}})]^3...$$
2- The derivative
$$\frac{d(\frac{1}{Q_{wi}I_r})}{d(\frac{1}{Q_{wi}})}$$
 is given by

$$\frac{d(\frac{1}{Q_{wi}I_r})}{d(\frac{1}{Q_{wi}})} = [b_1Q_{wi} + 2b_2Q_{wi}Ln(\frac{1}{Q_{wi}}) + 3b_3Q_{wi}Ln(\frac{1}{Q_{wi}})^2]^*$$

$$(Exp[b_o + b_1[ln(\frac{1}{Q_{wi}})] + b_2[ln(\frac{1}{Q_{wi}})]^2 + b_3[ln(\frac{1}{Q_{wi}})]^3)....$$
(A-10)

The calculations of the relative permeability and the relative mobility were performed using an Excel Spreadsheet constructed by Khairy, M. using the equations from (A-2) to (A-10).

The following steps are used to curve fit the experimental data and to determine both the relative permeability and relative mobility versus saturation curves using the constructed Excel Spreadsheet.

- 1-Plot Qo vs. ln Qwi and get the constants (a0, a1, a2,...) of the equation (A-7).
 - Then determined the derivative of equation (A-9), $\frac{dQ_0}{dQwi}$ and determine 2-

the value of the derivative (the slope of the curve) at the required Qwi using equation (A-9), which is fo.

3-Calculate injectivity, $Ir = (qt / \Delta p)$ at any flood stage / (qt/ Δp) at the start of injection

4-Plot ln(1/Qwi Ir) vs. ln(1/Qwi) and get the constants (b0, b1, b2,...) of the equation (A-8).

5- Then determined the derivative of equation (A-8),
$$\frac{u(\overline{q_{wi}l_r})}{d(\frac{1}{q_{wi}})}$$
 and

determine the value of the derivative (the slope of the curve) at the required Qwi using equation (A-10), which is m.

6-Calculate the average water saturation (Swav) using equation (A-3).

7-Calculate the water saturation at the outlet face (Sw2) using equation (A-4).

8-Calculate the oil relative permeability using the following equation: Kro = fo / m9-

Calculate the water relative permeability using the following equation:

$$k_{rw} = k_{ro} \frac{(1 - f_o)}{f_o} \frac{\mu_w}{\mu_o}$$

10- Oil and Water relative mobility λro and λrw are calculated using the following equations:

$$\lambda_{ro} = rac{k_{ro}}{\mu_o} ext{ and } \lambda_{rw} = rac{k_{rw}}{\mu_w}$$

- 11-Then, plot kro and krw vs. Sw2 curve.
- 12-Finally, plot λ ro and λ rw vs. Sw2 curve