

## A Modified Model for Estimating Initial and Gas Reservoir Reserves

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**Abstract** *A modified model is developed to determine initial gas in place and to predict the performance of any gas reservoir by using material balance approach and linear programming technique. Compaction of the aquifer rock, connate water expansion and/or expansion of water in the aquifer, shale water influx, and water encroachment from finite bounded reservoirs are included in the developed mathematical model. Each of these mechanisms are examined and their effects on the results of initial gas reserves and reservoir behavior are presented.*

**Keywords** Gas reservoir, gas reserves, initial gas in place.

### Nomenclature

$G_p$  = gas produced, SCF

$V_i$  = initial gas in place, CF

$V_f$  = gas remaining in the reservoir after producing  $G_p$  SCF of gas, psia

$P_i$  = initial reservoir pressure, psia

$P_f$  = pressure of the reservoir after producing  $G_p$  SCF of gas, psia

$Z$  = compressibility factor

$T$  = reservoir temperature, °K

$P$  = average reservoir pore pressure, psia

$B_g$  = gas volume factor

$S_w$  = water saturation

$C_w$  = water compressibility factor,  $\text{psi}^{-1}$

$P_R$  = current reservoir pressure, psia

$RF$  = ratio of aquifer to reservoir volume

$\gamma$  = shale fraction of the reservoir and aquifer volume

$\phi$  = porosity

$C_{sh}$  = bulk shale compressibility, psi

$C_r$  = rock compressibility,  $\text{psi}^{-1}$

$\beta_w$  = water formation volume factor

$W_e$  = water influx, bbls

### Subscripts

e = effective

w = water

r = rock

g = gas

i = initial

sc = standard conditions

## Introduction

The estimate of gas in place, recoverable reserve, and reservoir future life performance is of great importance for the natural gas industry. The rapidly growing energy demands of the world could not be satisfied without considering the natural gas industry. In order to make reasonable future recovery predictions, estimates of the initial gas in place must be made. There are three principle methods for calculating gas in place: (1) volumetric method, where reservoir rock volume is usually obtained by planimetry of isopachous maps of productive reservoir rock; (2) material balance, where an exact accounting of the materials that enter, accumulate in, or are depleted from a defined volume in a certain time interval; and (3) production decline approach, where decline curve analysis uses actual performance data for estimating reserve.

The following material balance equation was presented by Craft and Hawkins (1959):

$$(P_{sc}/T_{sc})G_p = (P_i V_i / Z_i T) - (P_f V_f / Z_f T) \quad (1)$$

Harville et al. (1969) presented some calculations using the following equation of total apparent reservoir pore volume as a function of pressure:

$$P.V = [G_i B_{gp} S_{wi} / (1 - S_{wi})][1 + C_w(P_i - P)] + (G_i - G_p) B_g \quad (2)$$

where,  $P$  is the average reservoir pore pressure, psia,  $S_w$  is the water saturation, and  $C_w$  is the compressibility factor of water,  $\text{psi}^{-1}$ .

Rosen (1975) developed an equation that can calculate connate water expansion:

$$1/B_w = (1/B_{ref})[1 - C_w(P_R - P_{ref})] \quad (3)$$

where,  $P_R$  is the reservoir pressure, subscript *ref* is referring to reference for water expansion.

Rosen (1975) also indicated that water influx caused by shale compaction can be represented by a barrier-type model, that is the rate of water influx is proportional to  $(P_i - P_R)$  or

$$W_e = (\text{constant}) (P_i - P_R) \quad (4)$$

Bernard (1987) developed a new method for estimating reserves and predicting the performance of abnormally pressured natural gas reservoirs. The method is applicable for reservoirs undergoing either depletion drive or limited steady-state water drive.

## The Modified Mathematical Model

The equation presented by Craft and Hawkins (1959) is modified to include the effects of water influx, connate water expansion, shale compaction, and rock compaction as follows.

### *Effect of Water Influx from Bounded-Aquifer and Connate Water Expansion*

In this case, we are concerned with water that comes from outside the sand body. Shale surface surrounding a sand reservoir will give up some water if the pressure differential is

large enough. When gas is produced, the pressure drops within the shale sand boundary. The volume of water is related to the areal extent of the aquifer and reservoir combined. At the same time, the connate water expansion depends on the size of the gas reservoir. This can be represented as:

$$\begin{aligned} \text{Water influx from bounded reservoir and connate water expansion} \\ = C_w * \Delta P [(S_{wi} + RF)] / (1 - S_{wi}) \end{aligned} \quad (5)$$

where,  $RF$  is the ratio of aquifer to reservoir volume and,  $\Delta P = P_i - P$ .

### **Effect of Shale Compaction**

Shales consist of small clay mineral grains that are, upon pressure increase, pressed closer together and the water in the intervening spaces is expelled. Wallace (1969) reported that the thickness of a firmly compacted shale has usually been reduced by 50% at about 5000 ft, all due to water loss. Therefore, the effect of shale compaction may be included in the mathematical model. The shale compaction can be represented by:

$$\text{Shale water influx} = C_{sh} [(1 + RF) / (1 - S_{wi})] * (\gamma / \phi) * \Delta P \quad (6)$$

where,  $\gamma$  is the shale fraction of the reservoir and aquifer volume  
 $\phi$  is the porosity, and  $C_{sh}$  is the bulk shale compressibility.

Equation 6 shows that the rate of pressure decline might increase with time because the compaction of shale buried in the rock will provide pressure support at the higher pressure level.

### **Effect of Rock Compaction**

The effective compressibility can be written as:

$$C_e = [S_{wi} / (1 - S_{wi})] C_w + [1 / (1 - S_{wi})] C_r + C_g \quad (7)$$

The equation shows the necessity of including results of connate water and rock expansion for gas reservoir conditions. Considering rock compressibility only, the rock compaction is represented by:

$$\text{Rock compaction} = C_r [(1 + RF) / (1 - S_{wi})] * \Delta P \quad (8)$$

Rock compressibility,  $C_r$ , becomes important for deeper high pressure reservoirs and at the same time gas compressibility,  $C_g$ , decreases with increasing pressure.

### **Effect of Water Production**

If during any interval,  $W_e$  reservoir barrels of water enter the reservoir as water influx and  $W_p$  surface barrels with a formation volume factor  $\beta_w$  bbl/STB are produced, the reservoir water volume at the lower pressure is

$$V_w = [\text{water influx enter the reservoir during the interval}] - [\beta_w W_p] \quad (9)$$

### Final Equation for Reservoir System

From Equations 1, 5, 6, 7, 8, and 9 the final modified material balance equation will be written as:

$$(P_{sc}/T_{sc})G_p = (P_i V_i / Z_i T) - (P V_i / Z T) [1 - (\Delta P / 1 - S_{wi}) \{C_w (S_{wi} + RF) + C_{sh} (1 + RF) \gamma / \phi (1 - S_{wi}) + C_r (1 + RF)\} + \beta_w W_p] \quad (10)$$

or

$$G_p = \beta_{gi} V_i - \beta_g [V_i - (V_i \Delta P) / (1 - S_{wi}) \{C_w (S_{wi} - RF) + C_{sh} (1 + RF) \gamma / \phi (1 - S_{wi}) + C_r (1 + RF)\} + \beta_w W_p] \quad (11)$$

The use of the equation to determine the reservoir behavior is extremely difficult. This is due to the difficulty in obtaining accurate values of the variables appearing in the equation such as aquifer and reservoir volumes, shale fraction of the reservoir, and compressibilities. To facilitate use of this equation for determining gas in place and recoverable reserve, linear programming optimization algorithm was used. The parameters such as water saturation, porosity, compressibility of rock, ratio of aquifer to reservoir volume, and shale fraction are adjusted in the linear programming model such as

$$\sum_{i=1}^N [(G_p)_{\text{simulated}} - (G_p)_{\text{observed}}]^2 \text{ is minimized} \quad (12)$$

The linear programming algorithm developed in a previous work (1969) was used to obtain initial gas and gas recoverable reserves at different intervals of pressure declines. The assigned values for the parameters used are reasonable. A set of simulation runs were performed, each of them using different parameter values. From the linear programming model the optimal parameter values were obtained.

### Applications

The developed gas model was applied to actual data shown in Table 1. Initial gas in place was calculated as 72 BSCF by using the linear programming model and Equation 11. Reservoir performance and pressure behavior is shown in Figure 1. Actual value was estimated as 70 BSCF (Sayyoub 1987). Therefore, the method presented in this article is able to determine quite accurately the initial gas in place within 3% of the actual value. A single phase (gas), two-dimensional dry gas reservoir simulator designed previously (Sayyoub 1987), in particular to study the validity of simulating the performance of any gas reservoir, was used to calculate initial gas. The estimated value of the initial gas in place by this simulator was found to be in good agreement with the obtained value by the presented model.

### Conclusions

The model developed in this article illustrates the utility of the approach presented in estimating the initial gas in place. The mathematical model developed can be used to predict the future reservoir performance and pressure behavior of any gas reservoir. The technique must be modified to include retrograde phenomena.

Table 1  
Anderson "L" Field Data\* and Calculations

(1) Time in months (t)	(2) Avg. Res. Press., psia	(3) Gp BSCF (10 <sup>-9</sup> )	(4) Bg Res ft <sup>3</sup> /SCF	(5) (Bg - Bgi) Res ft <sup>3</sup> /SCF	(6) (GpBg)/ (Bg - Bgi) (10 <sup>-9</sup> )	(7) (P <sub>i-1</sub> - P <sub>i</sub> )/2 = (ΔP <sub>avg</sub> )	(8) Σ <sub>i=1</sub> <sup>n</sup> (ΔP <sub>avg</sub> ) t <sub>n</sub> - t <sub>n-1</sub>	(9) (8)/(5)
0	9507	0	0.00311	—	—	—	—	—
3	9292	0.39	0.00313	0.00002	61.035	107.50	186.195	9.3 × 10 <sup>6</sup>
6	8970	1.64	0.00318	0.00007	74.503	161.00	542.18	7.74 × 10 <sup>6</sup>
9	8595	3.23	0.00321	0.00010	103.683	187.50	1040.39	10.40 × 10 <sup>6</sup>
11	8332	4.26	0.00324	0.00013	106.172	131.50	1141.13	8.8 × 10 <sup>6</sup>
12	8009	5.51	0.00329	0.00018	100.710	161.50	1703.93	9.46 × 10 <sup>6</sup>
15	7603	7.54	0.00335	0.00024	105.246	203.00	2290.00	9.54 × 10 <sup>6</sup>
17	7406	8.75	0.00338	0.00027	109.537	98.50	3600.54	13.33 × 10 <sup>6</sup>
19	7002	10.50	0.00345	0.00034	106.747	202.00	3679.29	10.82 × 10 <sup>6</sup>
21	6721	11.77	0.00351	0.00040	103.282	140.50	—	—
22	6535	12.80	0.00354	0.00043	105.3710	93.00	—	—
25	5764	17.28	0.00373	0.00062	103.959	385.50	—	—
31	4766	22.89	0.00440	0.00129	78.07	499.00	—	—
37	4295	28.14	0.00444	0.00133	93.94105	235.00	—	—

\* See Duggan 1972.

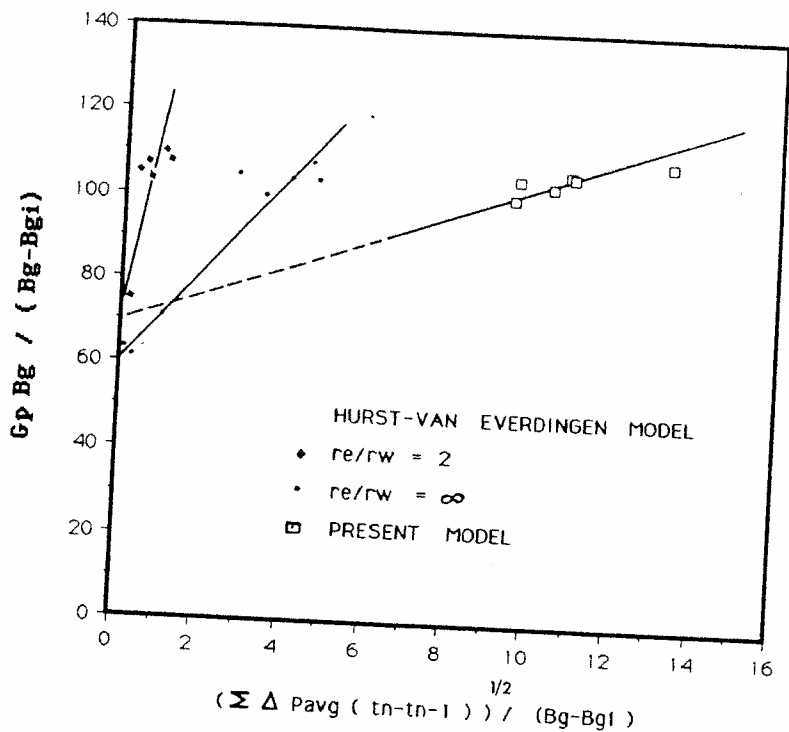


Figure 1. Determination of original gas in place.

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## **A Laboratory Study on Enhanced Oil Recovery from Safaniya Saudi Oil Field by Surfactant/Polymer Flooding**

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Safaniya field—and most Saudi reservoirs—is characterized by high formation water salinity—up to 30% by weight. Salt concentration has an important effect on both phase behaviour and displacement efficiency of surfactant flooding. This paper is concerned with the applicability of surfactant and polymer displacement to recovery of tertiary oil from the Safaniya field. Some available surfactants (Petrostep 420) were used and phase relations were obtained after equilibrium at reservoir temperature. Displacement runs were performed on unconsolidated cores. The effect of salinity (from 0 to 30%) on the process was studied.

It was found that the miscibility decreases with increasing salt up to about 15%, then increases at higher salt concentrations. Temperature increase decreases miscibility. Tertiary recovery was found to decrease with increasing NaCl concentration until about 10-15% NaCl, then increases and stabilizes at higher NaCl concentrations up to 30%. Recovery was found also to increase with increasing surfactant slug size, and to decrease with increasing temperature. This is the first study on the enhanced recovery possibility of Saudi reservoirs.

### **Introduction**

The development of oil reserves is of great importance for Saudi Arabia as well as for the rest of the world. This can be achieved either by the discovery of new oil fields or by increasing the recovery from the existing ones. Large quantities of residual oil will remain in Saudi oil fields after the primary recovery and water-flooding stages. Because of the large volumes of the Saudi oil fields, the amount of the residual oil will be enormous. Any method that can recover a significant part of this residual oil would be of great importance and should be investigated. Such

methods are termed Enhanced Oil Recovery (EOR) methods. Some and may be all of the EOR methods are suitable for Saudi reservoirs. Hot water injection and steam flooding may be suitable for medium viscosity oils and even *in-situ* combustion may be used in connection with the tar mat known to be present in the Ghawar field separating the oil and water zones. It is, however, felt that efforts in the first stage should be concentrated on research pertaining to chemical flooding techniques and particularly surfactant/polymer flooding. The objective of this research was to study the applicability of surfactant-polymer flooding as an EOR method for Saudi oil reservoirs. Since one of the significant characteristics of Saudi oil reservoirs is the high salinity of the associated water, it is necessary to investigate the phase behaviour and recovery behaviour by chemical displacement at comparable reservoir conditions of water salinity and permeability range. The temperature in Saudi reservoirs is about 72 °C which can be duplicated in the laboratory for these studies.

After a successful water or gas injection project, as much as 50% of the initial oil in place remains entrapped in the pores of the reservoir rock [1]. This remaining residual oil needs a very high pressure gradient to be mobilized owing to the capillary forces needed to drive the isolated oil bubbles through the narrow necks of the porous medium [2]. To recover this residual oil under the usually applied field pressure gradients, the interfacial tension between the oil and the displacing fluid must be either greatly reduced or completely eliminated. This can be done chemically by injecting solutions completely or partially miscible in both oil and water phases. Since these solutions are usually very expensive, slugs of these solutions are driven by water. Mobility control can be achieved by injecting a buffer zone of polymers [3].

Displacement by micellar solutions is one of the important tertiary recovery processes by chemical solutions. This process is known in the petroleum industry by several names. Hill *et al.* [4], Larson *et al.* [5], Shah *et al.* [6], and Van Poolen [7] name the process as surfactant flooding. The term 'micellar flooding' was used by Davis *et al.* [8], Gogarty *et al.* [9-12], Farouq Ali *et al.* [13], Gupta *et al.* [14], Sayyoub *et al.* [15] and Trusenaki *et al.* [16]. Based on interfacial tension criteria, Foster [17] and Bleakley [18] named the process 'low tension water flooding'. The term 'microemulsion flooding' was introduced by Healy *et al.* [19-22]. Holm [23] used the term soluble oil flooding. Bleakly [18] and Danielson [24] named the process 'Maraflood process'. The 'Maraflood process' was first introduced by Gogarty and Tosch [25].

Surfactant flooding involves sequential injection of a chemical slug, a polymer slug for mobility control, and brine to drive these solutions. This process has been studied by many investigators at different conditions [1-8]. Several experimental studies on surfactant polymer flooding indicated that phase equilibrium, interfacial tension, viscosity, wettability, and rate play an important role in the displacement process [9-13]. It is apparent that the surfactant flooding process is very much



dependent upon the particular properties of the fluids present and the rock characteristics. The salinity of formation water will affect the process greatly. No work has been done on high salinity effects.

The understanding of the mechanism by which surfactant solutions mobilize residual oil under tertiary conditions is needed in order to design rationally for field flooding. In addition to the economic considerations related to the cost of the surface-active-agents and polymer additives the high salinity condition for Saudi fields places some restrictions on the use of surfactant-type floods. To ensure optimal displacement efficiency and minimum surfactant loss, the injected micellar fluid should have the salinity giving minimum residual oil left when the mobility of all banks is equal.

A serious limitation on the use of surfactant floods is their incompatibility with and/or sensitivity to reservoir fluids (dispersion) and rocks (adsorption). It was found [26, 27] that divalent ions are notorious, particularly calcium ions which may exchange with the sodium ions of the petroleum sulphonates, thereby increasing their molecular weight and decreasing oil recovery effectiveness.

### **Experimental**

#### *Phase Behaviour*

Phase behaviour experiments were performed in order to establish ternary relations between surfactant, Safaniya crude and brine solutions. The effect of salinity and temperature on the miscibility was investigated. The physical properties of the phases were measured when equilibrium was obtained at room temperature and at 72 °C.

The required salt solution was prepared according to the specified phase composition. The blender was then tared and a quantity of sulphonate weighed in with the help of a glass syringe. Next, the required quantity of isopropyl alcohol was added using a burette. Oil was then added and all the ingredients were then mixed for approximately 5 min. The salt solution was then added a little at a time until all the salt solution was exhausted. After all the salt solution was added, the ingredients were then mixed for another 10 min. When the mixing was complete, the solution was poured into the graduated cylinder. The graduated cylinder was covered with aluminium foil and allowed to stand. The volumes of the aqueous and oleic phases were measured at room temperature at different times until equilibrium was obtained. The samples were then placed in an oven at 72 °C until equilibrium was obtained. The phase diagrams were calculated at this temperature. The available properties of Petrostep 420 surfactant are shown in Table 1. Properties of the used fluids are shown in Table 2. The change of the viscosity of the used polymer (Pusher 500-500 ppm) is shown in Fig. 2 as a function of shear rate.

Table 1. Composition of Petrostep 420 Surfactant.

Sulphonate actives	61.5%
Free oil	19.6%
Water	14.5%
Inorganic salt	4.4%
Equivalent weight range	410-430
Density (lbs/gal. @ 120 °F)	9-9.4

Table 2. Properties of Used Fluids.

Oil viscosity (50% volume Safaniya oil + 50% volume kerosene)	6 Cp
Surfactant slug* viscosity	4.31 Cp
Polymer solution used was 500 ppm Pusher	500
Viscosity shown in Fig. 2	
*Slug composition:	
Petrostep 420	15%
(60% sulphonate + 37% IPA)	
Water (distilled)	65%
Safaniya crude	20%

In order to study the displacement process by micellar solutions, runs were carried out using the displacement apparatus shown in Fig. 1. In each run, the model was saturated with brine under vacuum. Then brine was displaced by oil. Oil was displaced by injection of two pore volumes of brine to simulate primary and water-flooding phases.

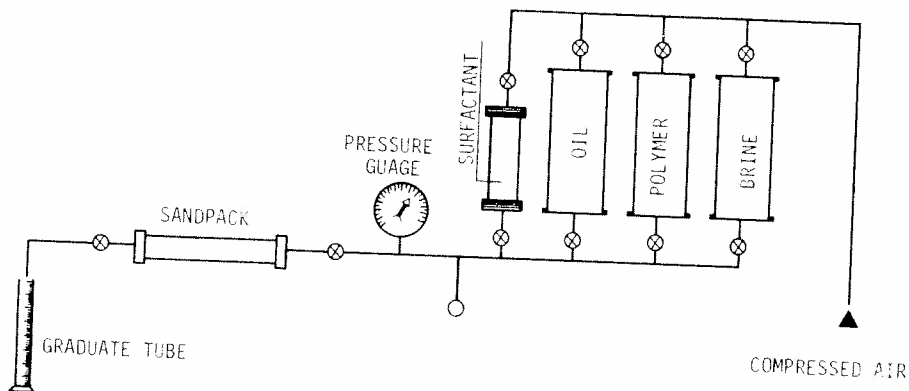


Fig. 1: Displacement Apparatus.

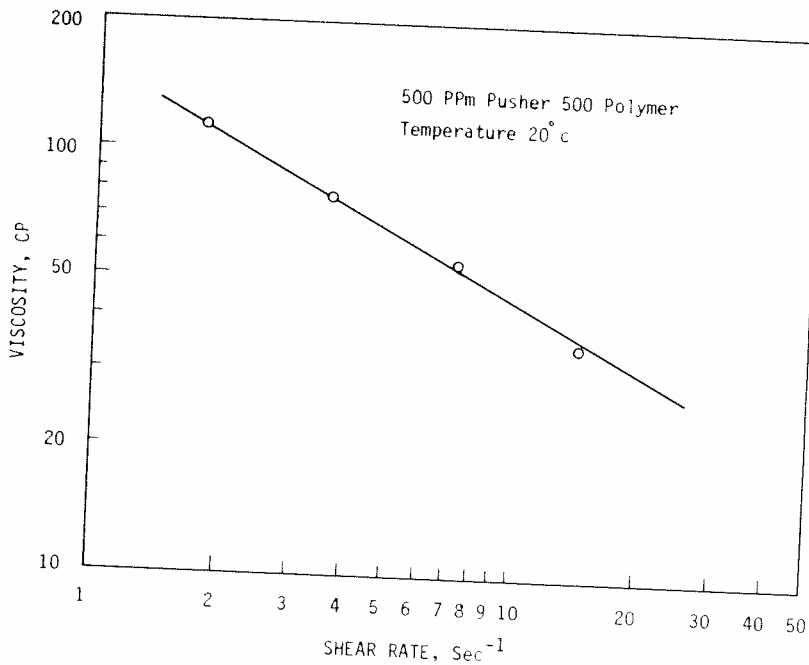


Fig. 2: Effect of Shear Rate on Pusher 500 Polymer Viscosity.

A tertiary process started with injecting a slug of surfactant solution. The slug sizes used in displacement runs were 20% PV, 15% and 10% PV. The surfactant slug was then driven by 50% PV of 500 ppm polymer solution and then by brine. The displacement process was stopped after injection of two pore volumes of the injected solutions.

## Results and Discussion

### *Effect of Salt Concentration On Phase Behaviour*

The effect of salt concentration on phase behaviour was investigated. Brines with different NaCl concentrations (0, 5, 10, 20, and 30 wt.%) were added separately with surfactant, and crude, and mixed. The ternary diagrams were constructed. Figures 3 and 4 are ternary phase plots to show the effect of salt concentration on miscibility behaviour of Petrostep 420. It is apparent from these plots that the size of the single phase region decreases with increasing salt concentration up to about 10%. For salt concentrations higher than 10%, the size of the single phase region increases. Salt concentrations around 10% are, thus, expected to have the lowest miscibility conditions. It is believed that this behaviour is due to the effect of salt on solution properties such as interfacial tension (Fig. 10).

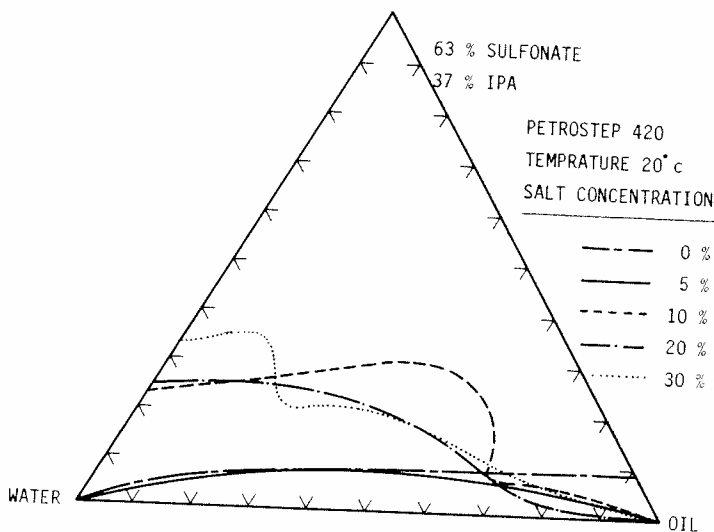


Fig. 3: Phase Diagram of Stepan S-420 Surfactant Safaniya Crude/NaCl-Brine System at 20 °C.

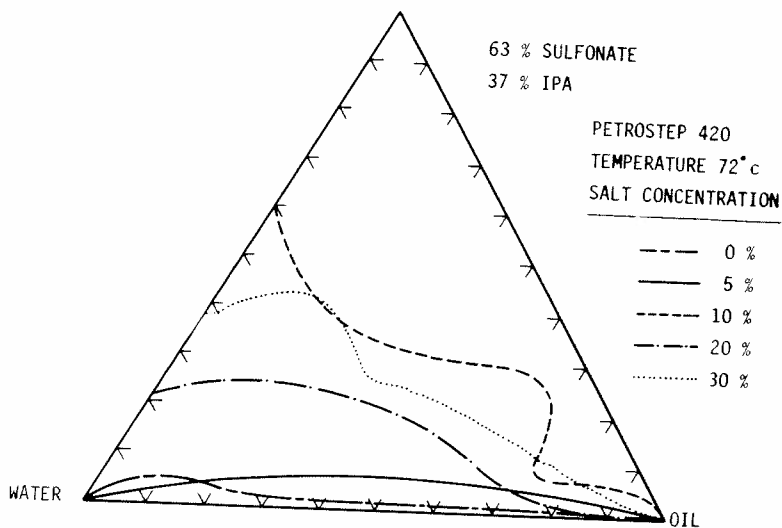


Fig. 4: Phase Diagram of Stepan S-420 Surfactant/Safaniya Crude/NaCl-Brine System at 72 °C.

*Effect of Presence of CaCl<sub>2</sub> on Phase Behaviour*

Formation waters usually contain salts other than NaCl. These salts can affect the behaviour of chemical solutions considerably. Divalent ions, particularly Ca<sup>++</sup>,

can influence the interfacial tension, viscosity, and phase stability of these solutions. Some investigators reported that  $\text{Ca}^{++}$  ions may precipitate the sulphonates and reduce miscibility during the enhanced recovery process [28]. Others found that a sharp tendency of interfacial activity occurs with  $\text{Ca}^{++}$  and they defined a region of optimum interfacial activity with  $\text{Ca}^{++}$  concentration.

Phase behaviour of Safaniya Crude, Petrostep 420 surfactant, and brines containing 10% salinity with different proportions of  $\text{CaCl}_2$  at 20 °C was obtained. The results are shown in Fig. 5 which is a ternary plot showing the single and two-phase regions for the different  $\text{CaCl}_2$  concentrations.

As shown in Fig. 5, the effect of adding different proportions of  $\text{CaCl}_2$  to the 10% salinity solution is remarkable. The miscibility increases with increasing  $\text{CaCl}_2$  concentration until about 20%, after which it decreases.

#### Effect of Temperature on Phase Behaviour

Surfactant studies should be performed at reservoir temperature so that the results can be applied to oil fields. Because of that, the effect of temperature on the phase relation of the surfactant under consideration was investigated. Figures 6, 7 and 8 are phase diagrams for 10, 20 and 30% NaCl salinity at 20 and 72 °C. The effect of temperature is in the direction of decreasing miscibility with temperature increase, which means lower surfactant effectiveness during displacement processes at reservoir conditions.

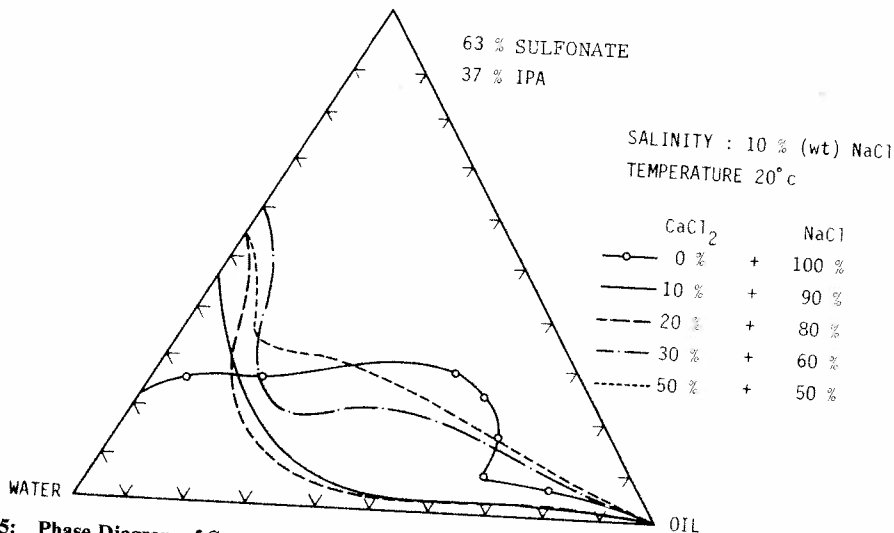


Fig. 5: Phase Diagram of Stepan S-420 Surfactant/Safaniya Crude and 10% Salinity of 0%, 10%, 20%, 30% and 50%  $\text{CaCl}_2$  and 100%, 90%, 80%, 70% and 50% NaCl at 20 °C.

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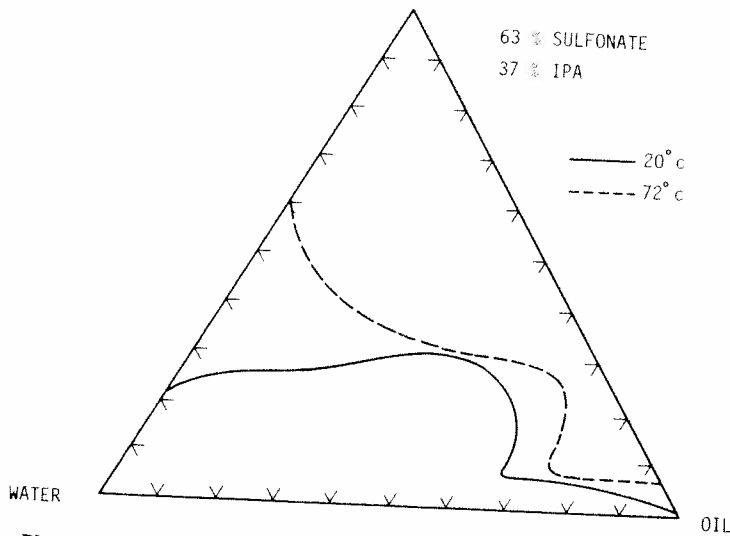


Fig. 6: Phase Diagram of Stepan S-420 Surfactant/Safaniya Crude/10%-NaCl-Brine System.

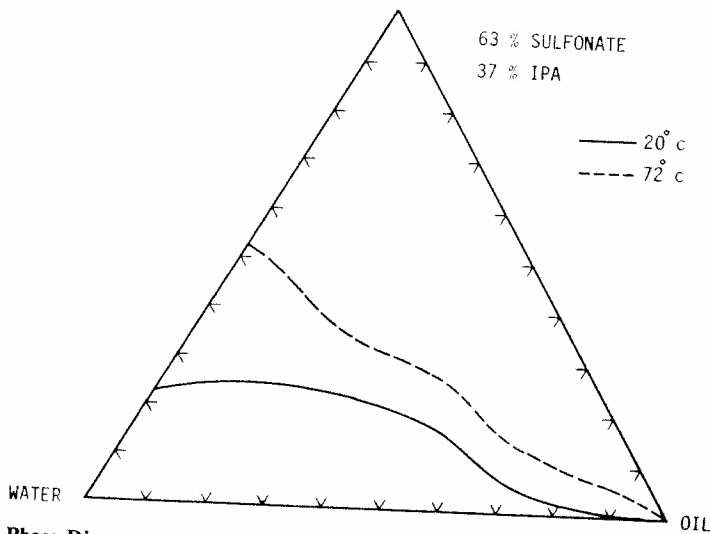


Fig. 7: Phase Diagram of Stepan S-420 Surfactant/Safaniya Crude/20%-NaCl-Brine System.

### Displacement Experiments

The effect of formation water salinity, formation temperature, and surfactant slug size on the efficiency of displacement was studied. Petrostep 420 was used, based on its performance in both phase behaviour and preliminary displacement.

Figure 9 shows the relation between NaCl concentration in formation water and recoverable oil expressed as percentage of Residual Oil In Place (ROIP). Recovery decreases with increasing NaCl salinity and reaches a minimum in the range 10-15% salinity. Recovery then increases and stabilizes at higher salinities. The change of interfacial tension with salinity was obtained as shown in Fig. 10. Also, the phase behaviour of S-420 with salinity as presented in Figs. 3 and 4 is indicative in the explanation of the effect of salt on oil recovery. The size of the single phase region decreases with increasing salt concentration up to about 10% and then increases at higher salt concentrations. Also the interfacial tension shows a maximum at about 15% NaCl salinity. This provides the explanation for the observed minimum in oil recovery with changes in salt concentration.

Figure 11 shows oil/water relative permeability ratio as a function of water saturation for different salinities. Welge's method [29] was used to calculate the relative permeability ratio. Here, the ratio increases with salt increase and reaches a maximum at 10% then it decreases again with increasing salinity. This indicates that the lowest oil recovery is obtained at about 10% salinity.

The effect of the presence of  $\text{CaCl}_2$  in formation water on residual oil recovery is shown in Fig. 12. Recovery increases with increasing  $\text{CaCl}_2$  in brine up to about 10% then decreases after that. This behaviour may be explained with reference to the phase behaviour diagram shown in Fig. 5, where the highest miscibility was obtained in the range 10-20%  $\text{CaCl}_2$  in total salinity (10%).

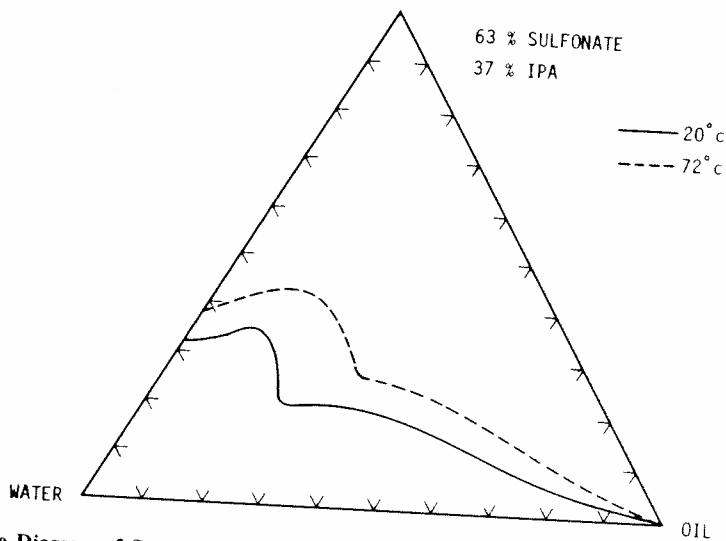


Fig. 8: Phase Diagram of Stepan S-420 Surfactant/Safaniya Crude/30% NaCl-Brine system at 20 °C and 72 °C.

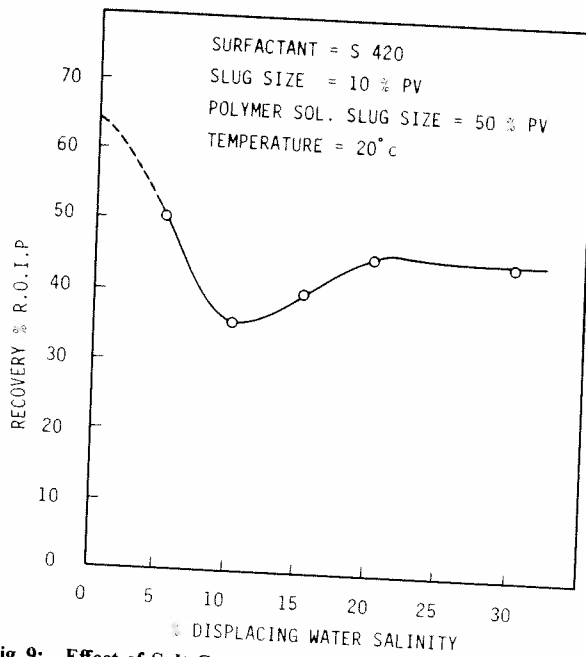


Fig. 9: Effect of Salt Concentration on Residual Oil Recovery.

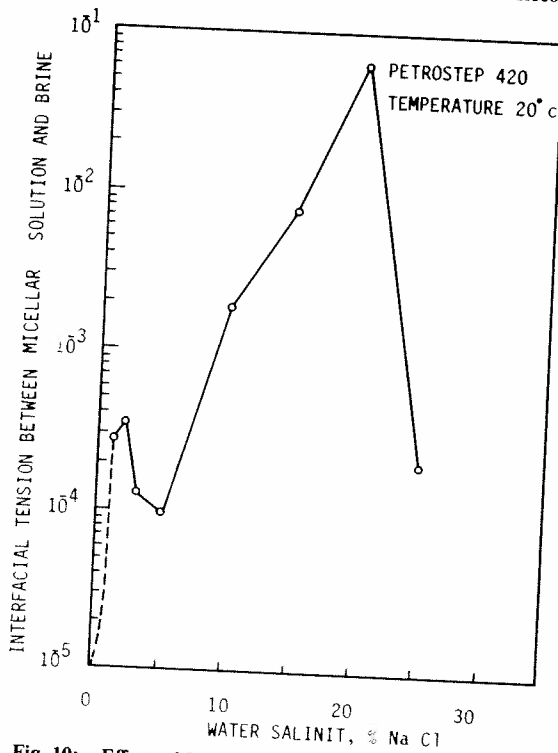


Fig. 10: Effect of Water Salinity on Interfacial Tension.



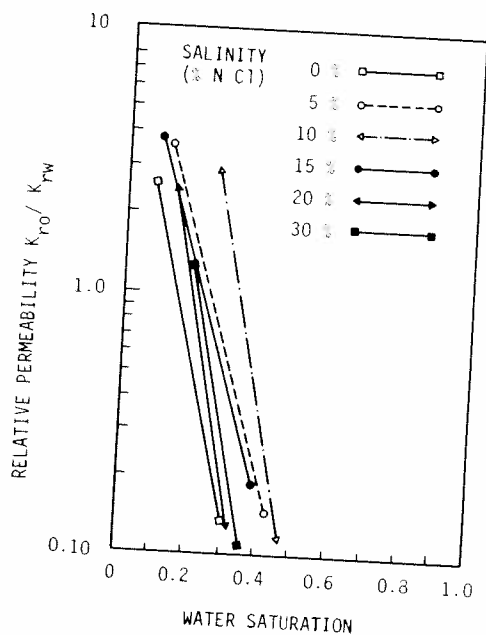


Fig. 11: Effect of Salinity on Relative Permeability Ratio.

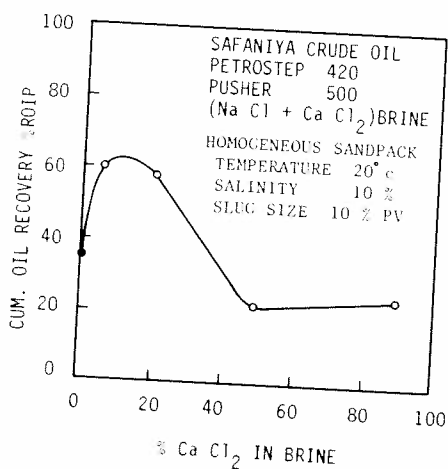


Fig. 12: Effect of % CaCl<sub>2</sub> on Oil Recovery.

The effect of formation temperature on residual oil recovery by surfactant-polymer displacement is shown in Fig. 13. The range of temperature used was from 20 to 90 °C, and the surfactant slug size used was 10% of the pore volume, and the polymer slug size was 50% PV. The formation water salinity was 20% NaCl. Recovery

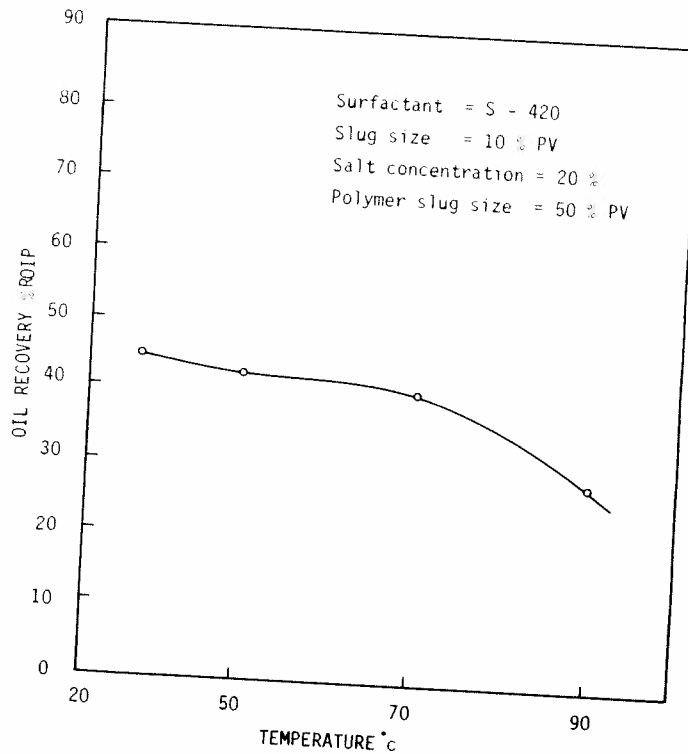


Fig. 13: Effect of Temperature on Cum. Oil Recovery. % ROIP.

was found to decrease with increasing temperature from about 45% Residual Oil In Place (ROIP) at 20 °C to about 30% at 90 °C. The interfacial tension between surfactant solution and brine was measured with temperature and its value was found to increase with temperature increase as shown in Table 3. This interfacial tension behaviour coupled with the change of phase behaviour with temperature as presented in Figs. 6, 7 and 8 explain the findings of Fig. 13.

Table 3. Interfacial Tension as a Function of Temperature.

Temperature °C	Interfacial Tension between Surfactant Solution* and Brine (10% NaCl) (dyne/cm)
30	$1.5 \times 10^{-4}$
50	$1.8 \times 10^{-4}$
70	$2.2 \times 10^{-4}$

\* Surfactant solution composition as shown in Table 2.

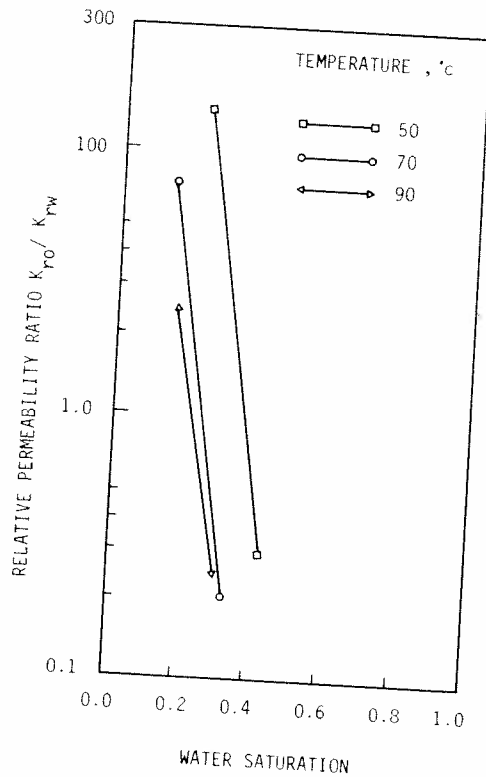


Fig. 14: Effect of Temperature on Relative Permeability Ratio.

The effect of temperature on relative permeability ratio  $K_{ro}/K_{rw}$  is shown in Fig. 14. Increasing temperature decreases the relative permeability ratio. This means that lower recovery would be expected from higher temperature reservoirs.

Change of residual oil recovery with the size of surfactant slug at 20 °C is shown in Fig. 15. Residual oil recovery increases as slug size increases.

### Conclusions

For the fluid and rock system investigated and at conditions prevailing in this work, the following conclusions can be drawn.

1. Salt concentration has an important effect on both phase behaviour of surfactant solutions and displacement efficiency.

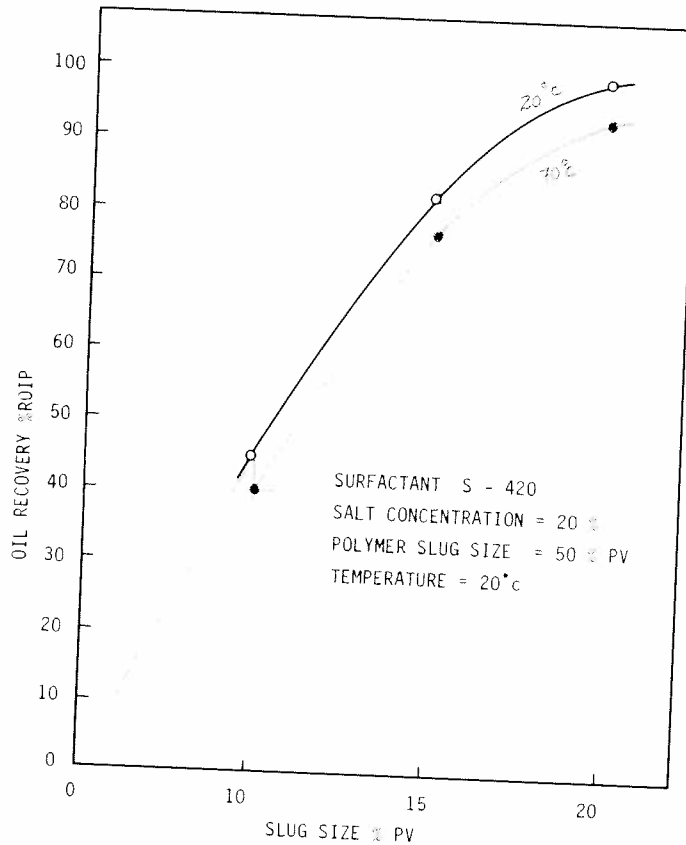


Fig. 15: Effect of Surfactant Bank Concentration on Oil Recovery.

2. Increasing salt decreases solution miscibility up to about 10%. Higher salt concentrations improve miscibility. The presence of  $\text{Ca}^{++}$  in formation water affects miscibility conditions.
3. Temperature affects surfactant solution phase behaviour.
4. Displacement runs were made on unconsolidated sandpacks and the effect of salinity, temperature and surfactant slug size on oil recovery was studied.
5. Recovery was found to decrease with increasing NaCl concentration until about 10-15% NaCl, then increases and stabilizes at higher salt concentrations. The presence of small concentration (lower than 20,000 ppm) of  $\text{Ca}^{++}$  in salt solution increases recovery.
6. Temperature increase results in increasing residual oil.
7. Increasing slug size increases oil recovery.

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## دراسة معملية على الاستخلاص المحسن للنفط من حقل السفانية باستخدام محاليل منشطات السطوح والبوليمر

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ص . ب . ٨٠٠ - الرياض ١١٤٢١ ، المملكة العربية السعودية

يتميز حقل السفانية - ومعظم الحقول السعودية - بزيادة نسبة الملوحة في المياه المصاحبة للنفط . وقد تصل هذه النسبة إلى ٣٠٪ بالوزن . ولتركيز الملح تأثير كبير على التصرف الطوري وعلى كفاءة الإزاحة بمحاليل منشطات السطوح . ويختص هذا البحث بدراسة مدى إمكانية استخدام محاليل منشطات السطوح والبوليمر لاستخلاص جزء من النفط المتبقي بحقل السفانية . ولقد تمت دراسة التصرف الطوري لنوع المنشط السطحي ٤٢٠ مع النفط الخام من حقل السفانية عند درجة حرارة المكنن . كذلك تم عمل تجارب للإزاحة على أوساط مسامية متماسكة وغير متماسكة واستخدمت مياه بنسبة ملوحة من صفر حتى ٣٠٪ .  
ولقد وجد أن درجة امتزاج المحاليل تقل بزيادة نسبة الملوحة حتى حوالي ١٥٪ ثم تزداد بعد ذلك . كذلك فإن زيادة درجة الحرارة تقلل من درجة الامتزاج . أما نسبة الاستخلاص من الأوساط المسامية فقد وجد أنها تقل بزيادة نسبة الملوحة حتى حوالي ١٠ - ١٥٪ ثم تزداد بعد ذلك بزيادة الملوحة حتى ٣٠٪ . كذلك فإن نسبة الاستخلاص تزيد مع زيادة حجم الجزء المستخدم من منشطات السطوح وتقل مع زيادة درجة الحرارة . وهذه هي الدراسة الأولى من نوعها على إمكانية استخدام الطرق الثلاثية في المكامن السعودية .