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A LABORATORY STUDY OF CHEMICAL ENHANCED OIL RECOVERY (CEOR) IN COMPARTMENTALIZED SANDSTONE RESERVOIR: A CASE STUDY OF A 2-D PHASE MACRO-MODEL RESERVOIR

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ABSTRACT

The chemical enhanced oil recovery (CEOR) in the compartmentalized sandstone reservoir (CSR) using a 2-D phase macro-model system was first reported in this work. The work investigated the effect of water flooding (brine 3.5 % w/v) and anionic surfactant (AOS, 2.0 % v/v) as a step forward to recover oil in the CSR. In the study, a total of 4 flooding scenarios was set for both water and AOS chemical flooding using two different sand particle; sand A (< 1 mm) and B (< 2 mm), respectively. The result indicated that pure sand B had the highest oil recovery by water flooding (80 %), followed by A:B (68 %), pure A (58 %), and B:A (49 %). However, after subsequent flooding with AOS chemical when water flooding could not further recover oil, water cut reduction and additional oil recovery (AOR) had been recorded in each case. The AOR in pure sand A was found to be 4 %, with water cut reduction of 20 %, while B was 2.7 % (water cut 13 %), A:B was 1.5 % (water cut 1 %) and B:A was 0.83 % (water cut 1 %). To account for these incremental amounts due to AOS, water/oil interfacial (IFT) studies were conducted. The result shows that, AOS had significantly reduced the IFT to 11.6 ± 3.097 mN/m. This study has demonstrated that water and subsequent chemical flooding in CSR has more effect in the homogeneous system (sand A and B) compared to the heterogeneous system (A:B and B:A). Nevertheless, approximately, more than 50 % of oil in place had been displaced in all flooding scenarios. Therefore, this finding is a step forward towards understanding the EOR in the CSR systems which would be useful in the body of scientific literature to benefit researchers from both academia and oil industry.

Keywords: enhanced oil recovery, compartmentalization, sandstone reservoir.

1. INTRODUCTION

Fossil fuels consist of oil, natural gas and coal, which account for 81 % of primary energy [1]. The world's increasing population has led to the over dependency on energy for domestic and industrial applications [2, 3]. Conventional methods (primary and secondary), which are the most widely utilized methods of extracting oil to the surface, could only recover about one third of the original oil present in the reservoir, leaving large portion of unrecovered oil in the underground formation [4]. Considering the increasing world's energy demand and depletion of natural reserves in non-compartmentalized reservoirs, alternative extraction methods are necessary to recover the remaining oil in the compartmentalized sandstone reservoir (CSR).

Enhanced oil recovery (EOR) techniques can significantly increase the production of oil and gas, and it attempts to recover oil beyond conventional methods [5, 6]. It targets the recovery of the other two third of the resource sitting in the reservoir [7]. In CSR, the EOR operation is challenging because hydrocarbon fluid is segregated into a number of hydrocarbon compartments by a barrier called boundaries [8, 9]. The boundaries are formed naturally by geological factors such as the depositional continuities or by faults and fault seal, especially in clastic reservoir [8, 10-12]. These boundaries can be a *static seal boundary,* where hydrocarbon fluids are not in communication with each other over geological time. While in the case of *dynamic seal boundary*, the barrier allows hydrocarbon fluid to flow and communicate through very low permeable zones [9, 10, 13, 14].

The application of EOR methods in CSR is not properly understood due to the aforementioned factors, leading to poor oil recovery. This is the major problem that has led to the abandonment of oil reserves in the CSR. However, efforts have been made by researchers from both academia and the oil industry to intensify research on the reliability of EOR methods that could extract oil from such unconventional reservoirs. Consequently, this study is aimed at investigating the effects of water and chemical flooding (CEOR) in CSR to find out the level of oil recovery and to provide useful scientific information that could benefit researchers from academia and industry.

2. MATERIAL AND METHODS

The silica sand particles were purchased directly from the local sand processing company at Tronoh, Perak, Malaysia. The crude oil was provided from the PETRONAS oil company, Malaysia. The aluminium foil (2.32 m^3) was also purchased from the commercial store. The salts used (Table-1) to make synthetic brine (3.5 %) were of analytical grades and purchased from the Sigma Aldrich Company. The construction of a reservoir model was fabricated by Zainal Enterprise Co., Perak, Malaysia.

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Table-1. The composition of synthetic brine used in this study.

S. no.	Salt name	Chemical formula
1	Sodium chloride	NaCl
2	Potassium chloride	KCl
3	Magnesium chloride hexahydrate	$MgCl_2.6H_2O$
4	Calcium chloride dihydrate	$CaCl_2.2H_2O$
5	Sodium sulfate	Na_2SO_4

2.1. Pre-treatment and characterization of silica sand particles

The silica sand particles were sieved to remove impurities, and two average diameter particle sizes; sand A (< 1.0 mm) and B (< 2.0 mm) had been obtained using an automated sieving machine. The two sand particles were then characterized using SAP (BET method) to find the pore volume, porosity and surface area, respectively. About 0.314 g of each sand sample was used and N_2 gas was automatically ramped at 10 ^oC/min for 4 hours until 350 ^oC degassing temperature. The surface area, pore volume and pore size were then recorded.

2.2. Crude oil characterization

The crude oil characterization was conducted according to American Standard Testing Methods (ASTM) as described in Table 2. The crude oil dynamic viscosity was measured using modular compact rheometre (MCR 302) at ambient temperature and constant shear rate of 50 s^{-1}. The density was performed using a benchtop digital Anton Paar density meter (DMA-450 M), while the pour point and wax deposition were analysed using the pour point analyser (Stanhope-SETA-94100-3) and Oxford density instrument (Oxford 4000), respectively. Similarly, saturates, aromatics, resins and asphaltenes, alternatively known as SARA analysis, was qualitatively and quantitatively analysed by column chromatography.

2.3. Design and construction of a 2-D phase sand pack reservoir macro-model

The sand pack reservoir model in this study has been developed for the first time. The construction of the reservoir model with the dimensions of 2 ft x 1.5 ft (Figure-1) was carried out using 2 transparent acrylic plates (top and bottom) with adjustable screw, an oil/water bank (rectangular shape) and gate for uniform flow, stainless steel wire mesh filters at the inlet and outlet regions, aluminium side frames with a thickness of 5 mm and acrylic 10 L capacity fluid container (tank) to deliver the fluid to the reservoir.

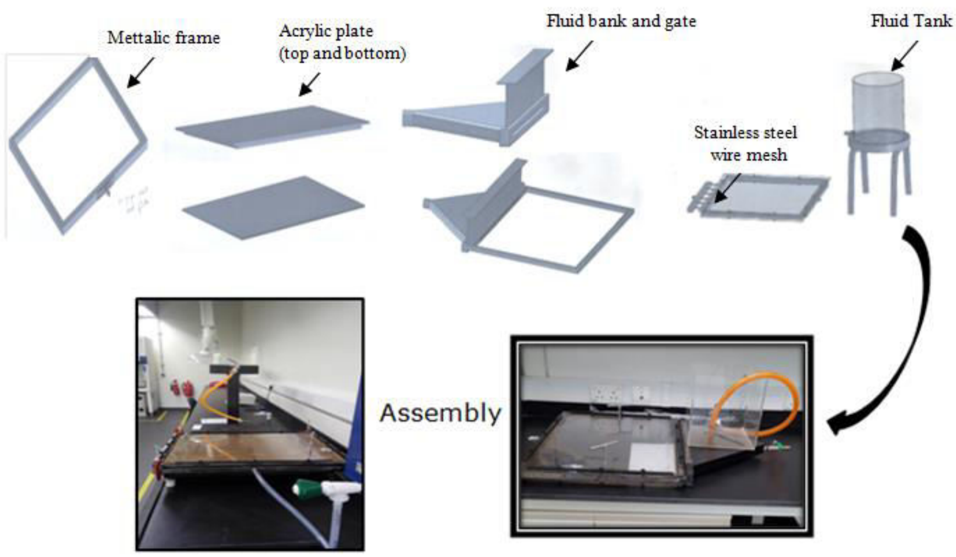

Figure-1. Design and construction of a 2-D phase sandstone reservoir model.

2.4 Determination of the dynamic flow in the 2-D phase sandstone reservoir model

The flow of fluid through the pack is the influence of gravitational force, it is necessary to determine the constant inlet and outlet flow of the liquid media. The sand pack was initially saturated with sand particles (mixture of sand A and B) and water was allowed to flow constantly from the fluid tank (height = 55cm) to the fluid bank and by regulating the flow inlet using a valve set at 90^o. The time take for water to drain from position y_1 to y_2 (60 cm) was about 18 min (Figure-2) to obtain a constant flow rate of 125 ml/min.

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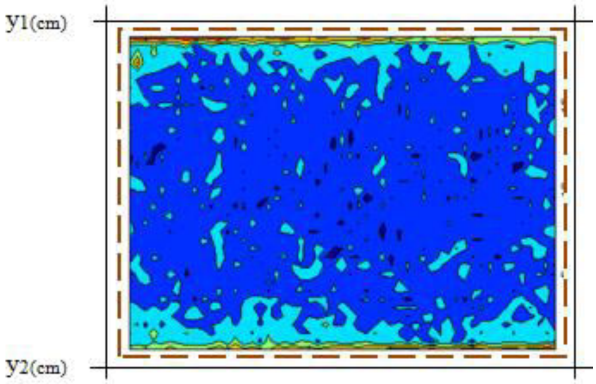

Figure-2. Schematic diagram of a 2-D phase sandstone reservoir model dimensional area.

2.5 Sand packing of a 2-D phase reservoir model

As mentioned in the 1.0 section in this paper, two kinds of reservoir boundaries are commonly found in compartmentalized reservoirs; *static seal boundaries*, which have total seals that block the communications of fluids from one boundary to another, and *dynamic seal boundaries*, which are semipermeable, and allow communications of fluid in slower rate. Figure-3 shows the image of the modelled 2-D reservoir during sand packing in this study, the uniform and partially perforated aluminium foil was used to represent a *dynamic seal boundary*. In the presence of the aluminium foil, the free flow of fluid across the sandpack had been restricted, which typically described the behavior of a *dynamic seal* type of a reservoir.

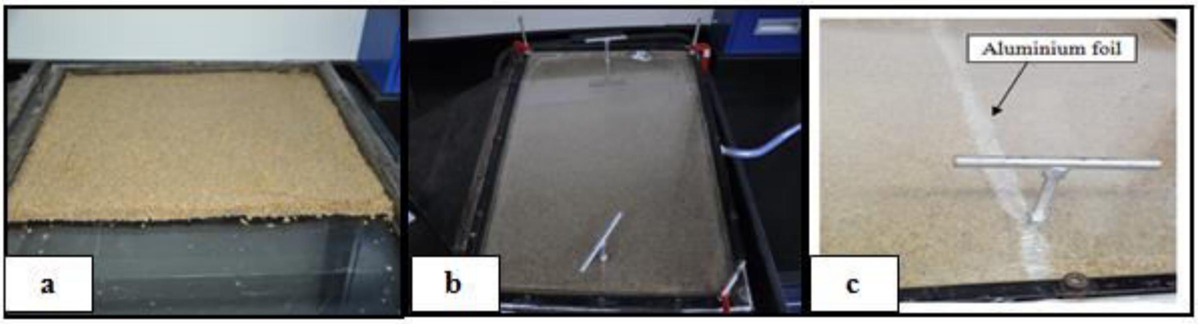

Figure-3. The image of the 2-D reservoir model: (a) during sand parking (b) after packing, and (c) aluminium foil serving as a boundary.

During the packing of a homogeneous reservoir system, the sand pack was fully packed separately with 100 % each of sand A and B, with a perforated aluminium foil partitioned in the middle of the reservoir pack, respectively. While in the case of heterogeneous reservoir system, two systematic variations of sand packing containing 50:50 % of sand A and B, respectively, had been employed (Figure-4). Firstly, 50 % of sand A having smaller grain and pore size was packed at the flow inlet region of the reservoir, while 50 % of sand B was then packed to occupy the other outlet flow region. At the middle of the sandpack, where the two different sand particles meet, the perforated aluminium foil was placed to separate the sand particle and created two different compartments. This system represents the flow of fluids from a lower permeability region to a higher permeability zone. In the second scenario, the same ratio of sands (A and B) was maintained, but the sand B with higher grain and pore size was packed at the inlet region and the sand A at the outlet region. Here, the system describes the flow of fluid from higher permeability zone to lower permeability zone.

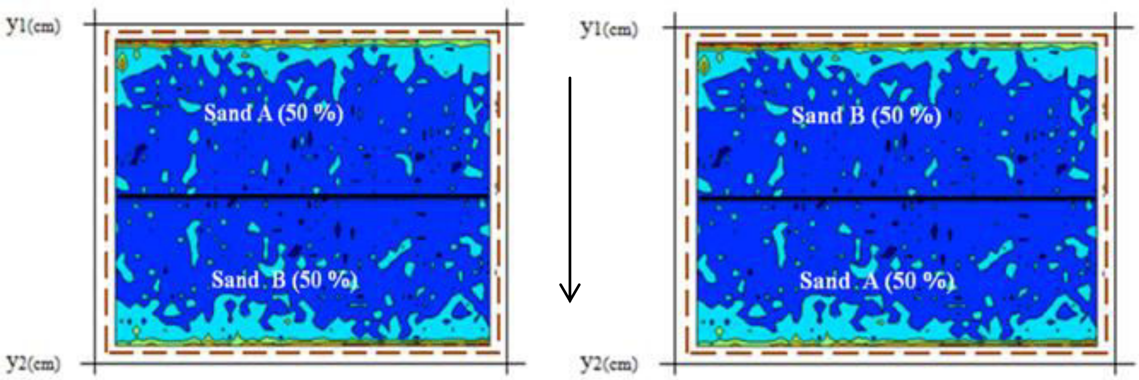

Figure-4. Schematic diagram of heterogeneous system of reservoir sandpacking.

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2.6 Oil recovery in the sand pack

After the sand packing, the experiments were conducted at 25 ^oC and 14.7 psi. The brine (3.5 % w/v) was firstly used to saturate the sand (Swi) to determine the pore volume (PV) by calculating the amount of brine required to saturate the sand pack matrix [15]. The oil was then flooded into the reservoir to displace the brine, until no further brine was discharged from the reservoir outlet, the initial oil saturation (Soi) (equation 1) and initial water saturation (equ. 2) was then calculated as below [16]:

$$Soi(\%) = \frac{OIP}{PV} * 100 \quad (1)$$

$$Swi(\%) = 100 - Soi \quad (2)$$

After the Soi, the oil recovery (OR) was started by flooding the pack with brine at the 125/min flow rate. This brine injection is considered to represent a secondary oil recovery commonly carried out in the oil fields during EOR operations [17]. The pressure distribution in the sand pack was maintained by keeping the volume of the injected fluids from the upper tank constant. When no further oil could be recovered by water flood, the oil recovery due to water flooding (OR_{water}) (equation-3) was calculated as follows:

$$\text{ORwater}(\%) = \frac{\text{Vol.ofoilrecoveredbywaterflooding}}{\text{OIP}} * 100 \quad (3)$$

The oil that could not be recovered by water flooding is termed as residual oil saturation (Sor) (equation-4) and was calculated as follows:

$$\text{Sor}(\%) = \frac{\text{OIP}-\text{Vol.ofoilrecoveredbywaterflooding}}{\text{OIP}} * 100 \quad (4)$$

After the water flooding, the chemical EOR (2 % v/v, AOS surfactant) was then continuously flooded to recover more oil from the Sor. The incremental amount of oil recovered (AOR) due to chemical slug was calculated as follows:

$$\text{AOR}(\%) = \frac{\text{Vol.ofoilrecoveredby chemical flooding}}{(\text{OIP}-\text{vol.of oil recovered by water flooding})} * 100 \quad (5)$$

2.7 Interfacial tension (IFT) measurement

The IFT between the oil and brine with and without the AOS surfactant were measured using a pendant drop interfacial tension analyser (model 700). The oil drop in the continuous phase of brine was kept for 1 min, and a camera (Newport M-RS6) attached to the equipment was used to captured the drop image and analysed to give the average IFT values.

3. RESULTS AND DISCUSSIONS

3.1 Silica sand and crude oil characterizations

The morphological properties of silica sand particles are presented in Table-2. It can be observed that sand B has higher surface area, pore volume and pore size than sand A.

Table-2. Morphological properties of the sand particles.

Sand particle	Particles size (mm)	Surface area (m^2/g)	Pore volume (cm^3/g)	Pore size (Å)
Sand A	< 1	0.2355	0.001127	202.158
Sand B	< 2	0.5685	0.001379	250.502

Table-3 presents the result of crude oil characterized in this study, because, the physical and chemical properties of crude oil are important during oil extraction in porous media [1]. From the table, it can be seen that the SARA analysis classified the crude as a light crude due to the high dominance of light proportions of organic components (51.780 %). This could be supported by the presence of low sulphur content (0.03 %) [18]. However, this crude is believed to have a good flow in the porous media because the pour point and wax depositions were not significant, API was high and viscosity was also low [19, 20]. Any crude with API > 25^o, could respond to water flooding because of the ability of water to push oil due to its high density [1].These properties are essentials and qualified the crude under study for use in the sand pack model under surface reservoir conditions. Heavy crude oil is not always suitable for laboratory EOR study at ambient conditions because of wax and asphaltenes deposition that may block the rock pores [15].

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Table-3. Physicochemical properties of the crude oil used in this study.

Test parameters	Method	Result
Density (g/cm^3)	ASTM D4052	0.7992
API (^{o})		43.100
Pour point (^{o}C)	ASTM D97-04	15.000
Viscosity (cp)		2.531
Wax content (%)		8.5100
Total Sulfur (%)	ASTM D5453	0.0300
Basic sediment and water (BS & W)	ASTM D4007	0.0000
SARA (%)		
Volatiles	Column chromatography	51.780
Inorganics		0.0100
Saturate		33.333
Asphaltene		0.0200
Resins		12.800
Aromatics		3.8700
Total recovery		101.80

3.2 Oil recovery

The result of oil recovery in this study had demonstrated the possibility of EOR operations in the *dynamic seal* type of a reservoir. Various EOR parameters such as PV, OIP, Soi, Swi, Sor and OR in this study are presented in Table 4, from the table, the value of PV and OIP conducted in triplicates varied in the range of 7-38 ml, accordingly. The Soi in the sand packs was found to be higher in heterogeneous systems (sand A:B and B:A) compared to homogeneous systems (sand A and B). This could possibly due to the combination of different morphological properties between the two sands leading to higher oil saturation. However, after the execution of water and chemical flooding in the CSR systems, the SOr in sand B:A and A were higher, which indicates high effects of compartmentalization in the two sandpacks. However, in all the flooding scenarios (water and chemical flooding), portion of OIP had been displaced from the sandpack systems.

Table-4. Oil recovery in sand packs after water and chemical flooding.

Parameters	Compartmentalized macro model sand sack			
	Sand A	Sand B	Sand A:B	Sand B:A
Sand ratio (%)	100	100	50:50	50:50
PV (ml)	2760 ± 10.0*	2600 ± 33.3	2000 ± 15.0	2842 ± 22.0
OIP (ml)	1940 ± 7.1	1921 ± 21.0	1514 ± 37.4	2350 ± 18.3
Soi (%)	71.4	73.8	75.7	82.7
Swi (%)	29.6	26.1	24.3	17.0
Sor (%)	41.9	19.9	31.7	50.9
OR_{water} (%)	58.0	80.0	68.0	49.0
$OR_{water + chemical}$(%)	60.0	81.0	68.3	49.4
$AOR_{chemical}$ (%)	4.0	2.7	1.5	0.83

Mean ± sdv

Figure-5 is the water cut curves observed from the systems, it can be seen from the results that the trends of water cuts is similar from what is commonly observed in the conventional flooding [21]. From the sand A system, it can be observed that after 18 minutes of water flooding, water cut was found to be nearly 100 % and after subsequent chemical flooding, water cut was reduced significantly by 20 % around 22 minute of oil production, which indicates the performance of chemical surfactants [3]. Whereas, in sand B, water cut reduction was 17 % around 32 minute of production, while both sand A:B and B:A, the water cut reduction were not significant (1 %) which resulted to low additional oil recovery (AOR).

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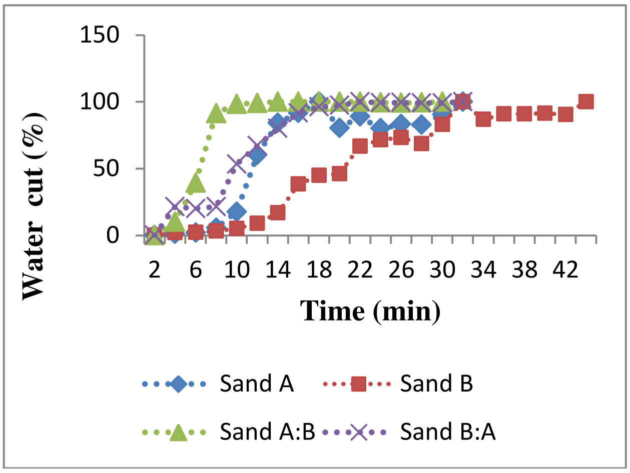

Figure-5. Water cut in the different sand stone reservoir.

Figures 6 and 7 describe the life history of the sandpacks interm of oil and water production cycles, respectively. From the figures, sand B had the longest oil production life (44 min) with total produced water of 73 %, while, A and B:A had the same oil production lives of 32 min. and produced water (A, 76% and B:A, 73%), and A:B had the shortest life (30 min and 84 %). This difference in terms of production time was attributed to different sand morphology between the two sand particles [1]. Produced water is considered a byproduct (and a waste) that comes out along with oil during extraction by secondary and tertiary methods [22, 23]. The cost of processing and disposing produced water determine the economic lifetime of an oilfield [24], as such understanding the mechanisms to cut produced water is crucial particularly in complex reservoirs like the compartmentalized reservoirs, as seen in this study.

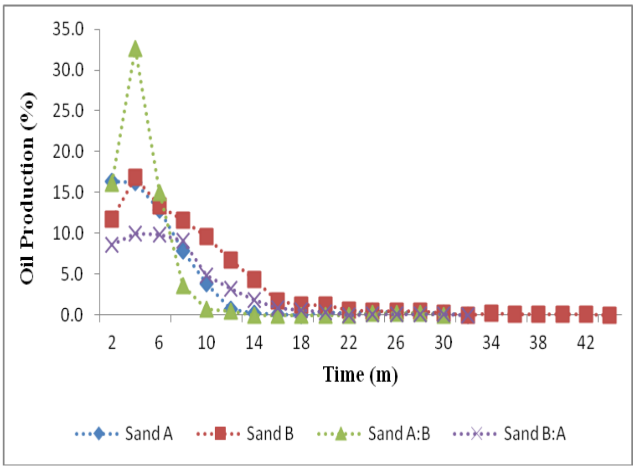

Figure-6. Oil production rate in different sand pack reservoirs.

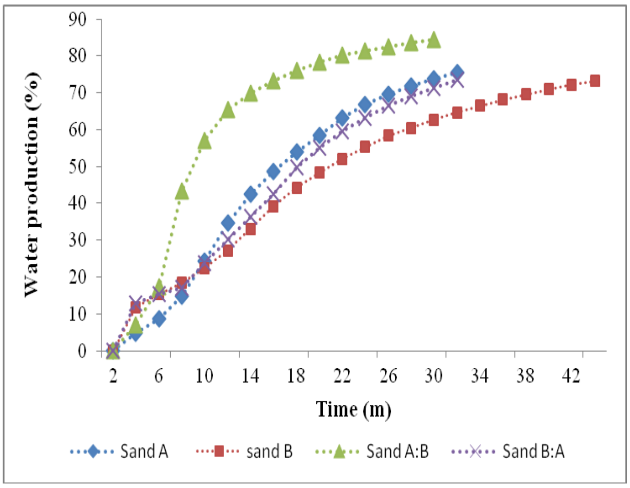

Figure-7. Total water production in the different sand pack reservoir.

However, from the water flooding cumulative oil recovery (COR) results (Figure-8), it can be seen that sand B (80 %) had the highest oil recovery by water flooding, followed by A:B (68 %), A (58 %), and B:A (49 %).

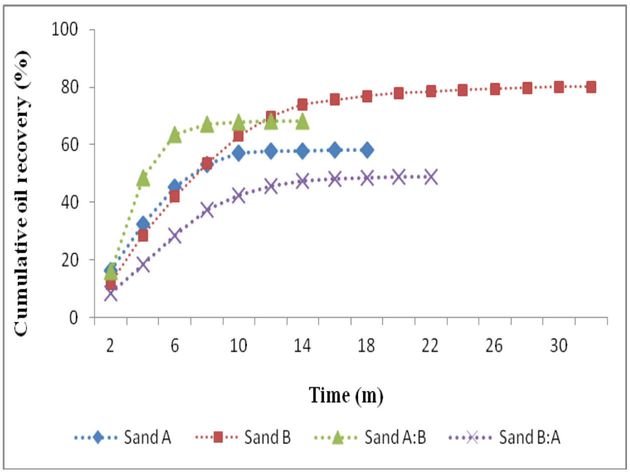

Figure-8. Cumulative oil recovery by water flooding in the sand pack.

However, despite the compartmentalization in the sand pack, after subsequent flooding with AOS chemical after water flooding could not further recover oil, additional oil recovery (AOR) had been recorded in each case (Figure-9). From the figure, the AOR in pure sand A was found to be 4 %, while B was 2.7 %, A:B was 1.5 % and B:A was 0.83 %. These incremental amounts were due to the interfacial effect of the AOS surfactant (2 % v/v) and sand morphology. The IFT between oil and brine without AOS was found to be 120.3 ± 9.8, while in the presence of AOS, the IFT was significantly reduced to 11 ± 3.097 which is in accordance with the literature that chemical surfactants mobilize the oil by reducing the interfacial tension between oil and water or oil and sandstone [25-27]. But the effect of chemical injection (AOR) in sand A was more significant compared to others. It was observed in this study that, the low amount of

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AORs in all the systems obtained was due to initial fingering channelling by the injected fluids. The channelling fingering was caused due to the initial water that bypassed the residual oil in the pack, and it was believed to have created the channelling pathways which caused the AOS chemical to flow in the same channel pathways as water, thereby recovering small portions of oil from the sand pack reservoirs.

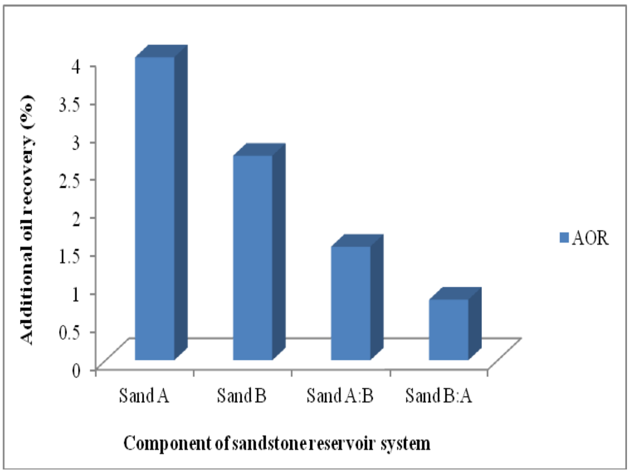

Figure-9. Additional oil recovery due to chemical flooding (AOS).

Figure-10 presents the total oil recovery in the CSR systems due to both water and chemical flooding which can be understood similar to the discussion of the aforementioned cumulative water flooding oil recovery.

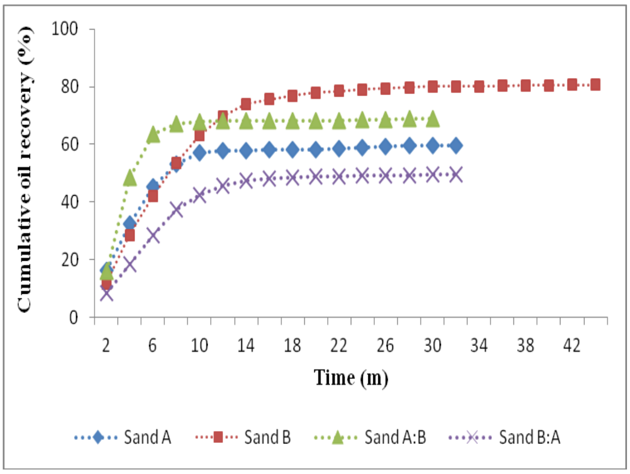

Figure-10. Cummulative oil recovery due to water and chemical flooding in the CSR systems.

CONCLUSIONS

In conclusion, the water and chemical flooding could be suitable methods of recovering oil from the CSR. Reason being that more than 50 % of oil had been recovered as demonstrated in this study. However, high produced water and fingering channelling remain the culprit that the remaining oil is left unrecovered in the reservoirs. Consequently, alternative strategies have to be developed to improve the conformance effect.

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