

An Experimental Study for Enhancing the Recovery Factor of Tar Barrier Heterogeneous Reservoirs

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Abstract

A number of major oil fields in the Arabian Gulf Region include tar barriers between oil and water zones. Such tar barriers partially or severely impede production as they resist fluid flow in the reservoir. Understanding tar distribution is therefore, essential for the prediction of reservoir performance under various developmental scenarios as in water flooding for secondary recovery. The objective of this study is to find out through experimental work the appropriate techniques for improving the recovery factor of different simulated tar quality that exists in the region. This investigation was carried out using different laboratory models with a view of selecting the appropriate one for the region. Consequently, improving tar mobility is one of our major objectives in this study. However, reservoir heterogeneity together with capillary pressure and dip angle would certainly affect such a process significantly.

Core samples taken from Sarah sandstone formation outcrops in Al-Qassim area of Saudi Arabia were selected for laboratory experiments which represent heterogeneous sandstone reservoir rocks. The petrophysical properties of these sandstone rocks were thoroughly investigated by studying properties such as permeability, porosity, relative permeability, recovery factor, grain size distribution and pore size distribution. Displacement runs were conducted in 4 in. and 1.5 in. diameter Al-Qassim sandstone outcrops composite cores, simulating tar and crude oil zones in series, at a constant injection rate of 2 ml/min. These experimental runs were conducted at simulated reservoir conditions of 60°C, 3500 psi confining pressure and 1500 psi back pressure.

Experimental results show that, the recovery factor was reduced by 26% approximately with tar present in the system. It increased by 9.2% approximately when the water flooding temperature was increased from 60°C to 90°C with tar. The recovery factor further increased to around 19% when a combination of hot water and solvent were used with tar.

Keywords: Tarmat; Heterogeneous; Oil recovery; Saudi Arabia

Nomenclature

- ϕ =Porosity, %
- Evp=Error in pore volume measurements.
- Evb=Error in bulk volume measurements.
- $E\phi$ =Error in Porosity Measurements.
- Eswi=Error in Water Saturation Measurements.
- EK=Error in Permeability Measurements.
- EORF =Error in an Oil Recovery Factor Measurements.
- OZPV=Oil Zone Pore Volume, ml
- TZPV=Tar Zone Pore Volume, ml
- TFPV=OZPV + TZPV= Total Hydrocarbon Pore Volume, ml
- N_p =Total Oil Produced at Five Pore Volumes of Water Injected, ml
- PV=Pore Volume, ml
- ORF=(N_p /OOIP)=Oil Recovery Factor, %
- OOIP=Original Oil in Place, ml.

Introduction

Many oil reservoirs are characterized by the presence of a highly viscous hydrocarbon layer (tarmat) at the oil/water contact. Such tarmats are found in many major oil reservoirs in the world and, particularly, in the Middle East. This tarmat barrier is in general very thick and could be as thick as the oil column in some reservoirs [1,2].

The thickness of tar-mat columns in traditional petroleum reservoirs varies from a few feet to several hundred feet. These tar-mat zones have additional bitumen or heavy oil, with in-situ viscosity above 10,000 cp and gravity below 10°API. They generally are located at the bottom of the oil column [3]. Al Bazzaz et al. studied models recovery of deep Tar-Mat available in substantial amounts in the Middle Eastern general and in Kuwait in particular as next generation and strategic reserves for extreme viscous and immobile solid-like unconventional oil [4]. Although Tar is believed to have originated from the same source that generated the oil during the migration time, the present characteristics of the tarmat are clearly different from the characteristics of the reservoir oil. The thickness of the tarmat varies from place to place in the same reservoir and sometimes reaches few hundred feet; while their extent can reach several kilometers. In Ghawar field, for example, the tar zone extends more than 25 km and reaches up to 150 m in thickness [5]. According to several geochemical studies presented by various researchers, tar mats form due to water washing, natural deasphalting, biodegradation, and gravity segregation, which results in grade variations in the composition with changes in depth [2,6].

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Depending on reservoir conditions and tar viscosity, field experience shows that some of these tar mats can become mobile under conditions of moderate differential pressure [1]. The presence of tar deposits at the oil/water contact in a tar mat reservoir can have serious adverse effects on the effectiveness of natural water drive as well as secondary recovery projects. When the tar mat completely surrounds the oil zone, the oil reservoir behaves like a finite lens where the pressure decreases rapidly as soon as the first well starts producing. This leads to an alarming increase in gas/oil ratio during the primary stage of depletion which has been the case with Minagish reservoir in Kuwait [1]. Another such example is El Bundug reservoir in Qatar [7]. In other situations where the tar has some mobility or thins out at some location, a breakdown of tar mat may occur as a result of the buildup of large pressure differentials across the tar layer leading to severe water coning. Al-Mansour et al. [8] investigated three enhanced oil recovery (EOR) methods in order to develop a quantitative measure of recovery yields from samples of tar mats found in carbonate rock. Toluene, hot water, and surfactant solution were applied separately on 60 samples collected from five different cores (12 samples from each core) all taken from a tar-mat zone at different depths [8]. Published research on the recovery of heavy oil from tar mats is relatively rare. Physical and chemical studies on the displacement and categorization of tar mats in the consolidated matrix are limited. Harouaka et al. conducted physical and chemical characterization studies of tar mats from a carbonate reservoir in Saudi Arabia, finding that the tar-mat properties varied with the depth and area within the same field [9,10]. A study on cold water flooding in a tar mat reservoir laboratory model (composite Berea sandstone core) was carried out by Abu-Khamsin et al. [11]. The results showed that oil recovery slightly decreases as the viscosity-thickness product of the tar zone increases. Okasha et al. conducted another study of oil recovery from a tar-mat reservoir. The results showed that higher hydrocarbon recoveries were obtained when combining hot water and two types of solvent flooding (naphtha and reformate) than when using hot water alone at 103 and 106°C, respectively. Furthermore, an optimum slug size for both solvents that maximizes the net hydrocarbon recovery was found. These optimum sizes for reformate and naphtha were 9.45 and 10.93% total hydrocarbon pore volume (THPV), respectively. Solvent slugs that are larger or smaller than this optimum size are less effective [12]. Another study was conducted by Harouaka and Asar [13] on tar properties and methods for improving injectivity in tar mats using naphtha and steam. The purpose of this study was to investigate some techniques to improve the tar mobility with the aim of tar displacement in a tar mat reservoir and the effect of such techniques on oil recovery in this kind of reservoir. Specifically, the use of a combination of solvent and hot water to displace the tar was evaluated. The effects of temperature, solvent slug size, type of solvent, injection rate, and injection mode on recovery were examined in detail. A reservoir laboratory model representing the tar and oil zones was simulated by a linear composite core. However, Al-Mansour, et al. [14], Tar-Mat is a reservoir that contains massive amounts of extra viscous crude oil in relatively tight-to-good pore rock system. Tar-Mats in the Middle East are found in carbonate reservoirs and they are rich in total organic compounds (TOC), greater than 20%. This oil has substantial large amounts of sulfur; more than 7% by weight is common. The measured oil gravity is best described as crude oils less than 5°API, with viscosity equivalent to Septillion (10^{24}) centipoise or higher, and henceforth, the mobility (permeability/viscosity) ratio is almost zero. Therefore, this rich organic matter physical state is described as solid-like and extremely immobile especially at natural reservoir energy settings [14]. Thermal Oil Recovery (Hot water/toluene Flooding) does not affect the environment in terms of the disposal because Toluene considers one

of the green solvents listed by the American Chemical Society (ACS). For water and air environment plus health and safety uses, toluene considers a toxic and dangerous solvent when using large quantities for long periods.

Experimental Apparatus

Core Flooding System CFS-200 (Figure 1) was used to pump hot water, solvent and a combination of hot water and solvent through core plugs that were saturated with tar. All experiments were conducted using core plugs from Sarah sandstone formation outcrops in Al-Helallah town in Al-Qassim province in Saudi Arabia. This formation belongs to Silurian age in the Paleozoic era and contains neither oil or gas nor water [15]. This sandstone is red to brown in color (Figure 2). All cores were around 4 inch in length, 1.5 inch in diameter and had porosities ranging from 25-28%, and permeability from 371 to 517 md. The core plug were cleaned and dried in an oven at 105°C, then saturated in a brine solution with 1% salinity using a desiccator for 24 hours (Figures 2-6) before crude oil injection to confirm that plugs are air evacuated and saturated. Then, the samples were individually held in the core holder and brought up to reservoir conditions with a



Figure 1: Core flooding system CFS-200.



Figure 2: Al-Qassim core plugs.



Figure 3: Core plugs in oven.



Figure 4: Desiccator apparatus.



Figure 5: Soxhlet extractor apparatus.

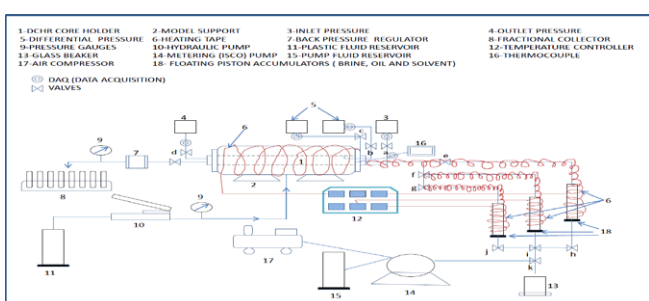


Figure 6: Schematic diagram of core flooding system CFS-200.

confining pressure less than 3,500 psi to simulate the overburden and heated to 60°C to simulate the reservoir temperature. A back pressure of 1,500 psi was maintained to simulate reservoir pore pressure. The back pressure also minimized the effect of any air which might be present in the core plugs and kept any generated gas in the solution.

A schematic of the core-flooding set-up used in this study is shown in Figure 6. It consists of the fluid injection system, a rubber sleeve core holder mounted inside a TEMCO, s DCHR core-holder made of stainless steel and designed for consolidated core samples of up to 12 in. in length and 1.5 in. in diameter. It is rated to 10,000 psi confining pressure and temperature of 350°F. This core holder is connected to Floating Piston Accumulators (FPAs) which hold the brine, solvent and the crude oil used for the displacement runs. These FPAs and core holder were surrounded by heating tape to keep the system at the required reservoir temperature. Also, the experimental apparatus consisted of a pressure transducers, core thermocouple, temperature controller system, back pressure regulator, data acquisition and fractional collector.

In all experimental runs, the brine was used only for clean rock and with a salinity of 1% (10,000 ppm). This brine comprises of 58% NaCl, 32% MgCl₂ and 10% CaCl₂ solution. The FPAs were connected in parallel and flow was routed using flow control valves. Detailed description of each component of the apparatus as well as configuration of the core holder and end plugs are found elsewhere [16].

The Crude oil and brine water were injected at constant rate of 2 cc/min for all experimental runs. Saturation of cores with tar was carried out using a special tar saturation setup (Figures 7 and 8). Saturation with tar was done at temperature 150°C using the core holder. Figure 8 shows a schematic of the tar saturation set-up. After loading the cores to be saturated with tar and assembling the core holder, a confining pressure of 4350 psi was applied. Vacuum was pulled on the system for several hours. Once the core holder and the transfer cell have reached the desired temperature, tar injection commenced at very low rate 1 cc/min. During tar injection, vacuum was pulled continuously to help the tar move toward the production end. Injection was carried out in such a manner that the injection pressure was always considerably less than the confining pressure to avoid by-passing the core plugs. Pulling of Vacuum was stopped once tar was observed at the outlet, but injection was continued until enough tar was produced to ensure 100% saturation. The core holder was then dismantled and the saturated cores were placed in a perfectly sealed container until ready to be used. Cores for experiments involving the same tar viscosity were saturated together. Pore volumes of the tar core plugs computed by tar saturation are compared with those computed by water saturation in Table 1. The



Figure 7: Tar saturation setup.

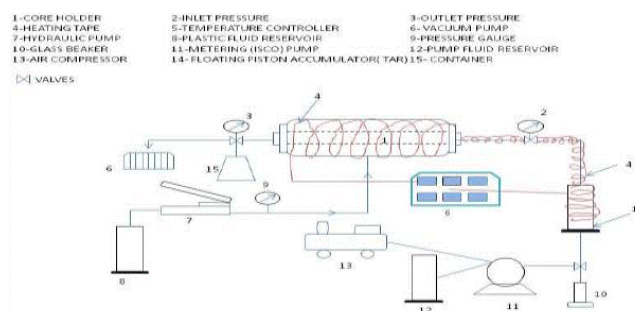


Figure 8: Schematic diagram of Tar saturation setup.

| Run No. | Length cm | Pore volume cc | |
|---------|-----------|----------------|-------|
| | | Tar | Water |
| 1 | 2.5 | 6.74 | 7.12 |
| 2 | 3.2 | 7.39 | 9.12 |

Table 1: Tar pore volume as computed from water saturation and Tar saturation separately.

| Fluid Name | Viscosity mPa.s | Density g/cc |
|------------------|-----------------|--------------|
| Brine | 1.15 | 1.005 |
| Ratawi crude oil | 39.59 | 0.891 |
| Heavy Ratawi oil | 6500 | 0.924 |
| Tar | 10,000 | 1.069 |
| Toluene | 0.6 | 0.866 |

Table 2: Physical properties of the fluids at 22°C.

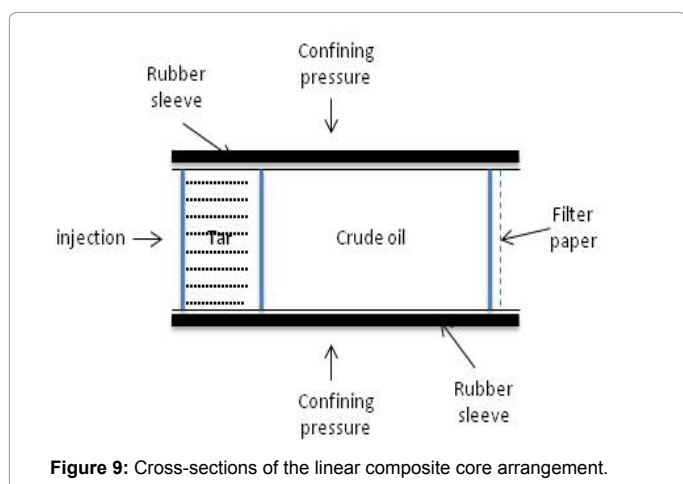


Figure 9: Cross-sections of the linear composite core arrangement.

data proves the success of the tar saturation process, as the water and tar volumes are reasonably close.

Fluids Description

In this study, Ratawi Hout crude oil was used as the oleic phase and a solution of 58% NaCl, 32% MgCl₂ and 10% CaCl₂ (1% salinity=10,000 ppm) in distilled water was used as the aqueous phase. The tar phase was prepared by evaporating a batch of heavy Ratawi crude oil until it a viscosity of about 10,000 mPa was reached at room temperature. Toluene was selected as solvent. The physical Properties and Characteristics of oil, brine, tar and solvent are given in Table 2.

Experimental Procedure

The saturated core plugs to be used in a flooding experiment were always arranged in the order shown in Figure 9. Filter paper was placed behind core plugs to prevent lines clogging by sand grains. The composite core was loaded into the rubber sleeve, and the core holder was assembled in the experimental set-up as shown in Figure 6.

To conduct a displacement run, the following steps were performed:

- A confining pressure of 3500 psi and temperature of 60°C were applied in all displacement runs (except during tar saturation, where a confining pressure of 4300 psi and temperature of 150°C were applied). The FPAs containing the fluids were heated up to 60°C using flexible heating tapes wrapped around them and around all lines were connected to core-holder.

- Back-Pressure of 1500 psi was applied in all displacement runs.

- After temperature equilibration, injection of fluids (brine, oil and solvent) was started at a constant rate of 2.0 cc/min and was continued for 5 PV (pore volumes).

- After a run was completed, the core-holder was dismantled and tar displacement vessel was estimated carefully. Core plugs making up the oil and tar zones were then extracted and cleaned for the next run using the solvent extractor apparatus, Figure 5.

Experimental Results and Discussion

Solubility of tar

Solubility tests were carried out to determine the response of the used tar to solvent type. Standard solubility tests were conducted at room temperature (22°C). 1 ml of solvent was added to 1.778 ml of tar. The mixture was allowed to react for one minute, addition of solvent was continued until tar was dissolved completely in solvent (Figure 10). Solubility was determined as the volume of solvent needed to completely dissolve the specific volume of tar. Table 3 shows the solubility tests for group of solvents. Toluene represents the most appropriate solvent, based on its ability to dissolve tar (toluene dissolved tar at the minimum volume and time).

Flooding results

In this study, all displacement experiments were conducted on 4 in. length Al-Qassim sandstone formation composite cores. The results are discussed with regard to the effect of hot water driven hydrocarbon solvent injection on oil recovery factor. Specifically, the effects of temperature and hot water plus solvent on recovery factor are presented. A total of 15 experimental runs were carried out following the experimental procedure described earlier. Eleven tests were performed at 60°C temperature (7 runs without tar and 4 with tar) while 4 runs were performed at 90°C in presence of tar and combination of hot water and solvent flooding.

Effect of temperature on recovery

A hot-water flooding (at 60°C) for two core samples A1&A11 and another hot-water flooding (at 90°C) experiments were conducted with

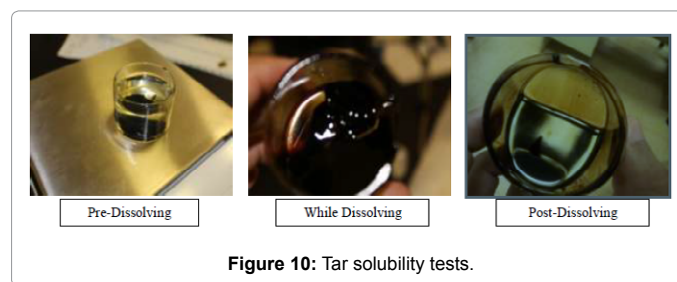


Figure 10: Tar solubility tests.

| Solvent Type | Solvent Wt, gm | Tar Wt, gm | Time min | Solvent Vol., cc | Tar Vol., cc |
|--------------|----------------|------------|----------|------------------|--------------|
| Toluene | 3 | 1.9 | 5 | 5 | 1.778 |
| Chloroform | 7.5 | 1.9 | 9 | 9 | 1.778 |
| Naphtha | 9.3 | 1.9 | 10 | 10 | 1.778 |
| N-Hexane | 9.5 | 1.9 | 25 | 25 | 1.778 |
| N-Heptane | 17.7 | 1.9 | 30 | 30 | 1.778 |
| Acetone | 27.4 | 1.9 | 40 | 40 | 1.778 |
| Kerosene | 10.8 | 1.9 | 15 | 15 | 1.778 |

Table 3: Tar solubility test results.

no solvent injection. Graphs of recovery versus the volume of water injected for both runs are shown in Figures 11 and 12. It was observed from Figures 11 and 12, that the hot water flood ($T=90^{\circ}\text{C}$) gave a recovery, R , of 44.70% for core A1 and 48.57% for core A11 which was substantially greater than that of the other flood ($T=60^{\circ}\text{C}$) with a recovery of 35.26% and 39.5 respectively. This is clearly a result of the reduction of tar and oil viscosities with temperature and enhancement of displacement efficiency due to improvement of tar and oil mobilities. Also, the increase in temperature causes a decrease in the interfacial tension between tar and brine as well as between oil and brine. Such a decrease in IFT reduces the effect of capillary forces which causes a decrease in the residual oil saturation.

Effect of solvent on recovery

The combined use of thermal and miscible displacement methods can be effective due to their individual favorable effects on the mobility ratio and IFT. In this study, solvent toluene driven by hot water was employed. Figures 13 and 14 show graphs of the hydrocarbon net recovery, R , versus water injected volume. It can be seen that R increases as the solvent (toluene) uses. It is observed from Figures 15 and 16 that the combination of hot water and solvent flooding gave a recovery of 53.00% for core A1 and 58.63% for core A11 in presence of tar which was substantially greater than that of the other flood (hot water alone) which gave recovery of 44.70% and 48.57% respectively. This is clearly a result of reduction of tar and oil viscosities with temperature and the injection of a solvent slug followed by hot-water flooding disperses the tar layer and establishes adequate communication between the water

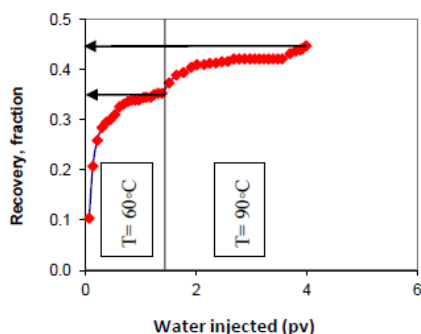


Figure 11: Recovery vs. water injected at different temperatures for core A1.

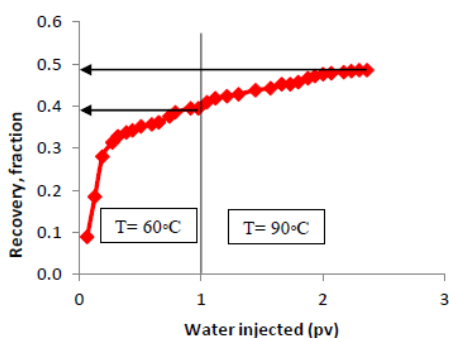


Figure 12: Recovery vs. hot Water injected at different temperatures for core A11.

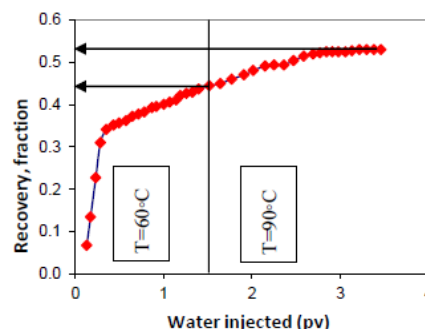


Figure 13: Recovery vs. combination of hot water and solvent injected for core A1.

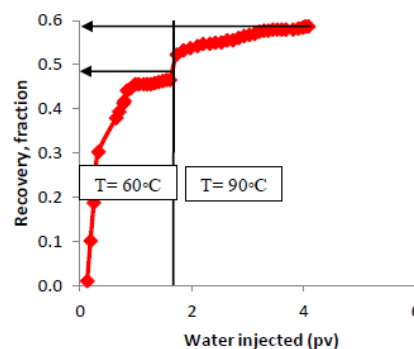


Figure 14: Recovery vs. combination of hot water and solvent injected for core A11.

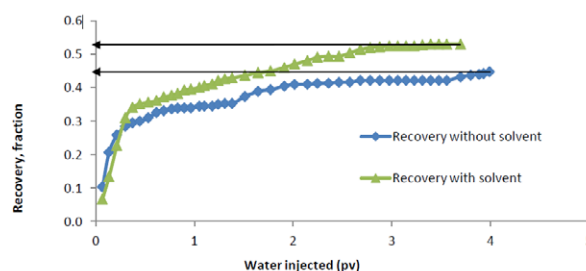


Figure 15: Comparison between recoveries when hot water or combination of hot water and solvent was injected for core A1.

and the oil zone. Finally, Figure 17, Tables 4 and 5 summarize the problem of tarmat barriers and comparison between recoveries with or without tar when hot water or combination of hot water and solvent was injected at different temperatures.

Simple economic analysis

Consider a hypothetical economic analysis scenario in which tar-mat/Oil samples A1 and A11 have the following characteristics: porosities of $A1=0.253$ and $A11=0.259$, water saturations of $A1=0.338$ and $A11=0.336$, a hypothetical field area of 1000 acres, a hypothetical tar-mat thickness of 500 feet and a hypothetical formation volume factor of 1.1 reservoir barrels over stock tank barrels. The amount of tar-mat oil in place is going to be 590,616,540 barrels of immobile for

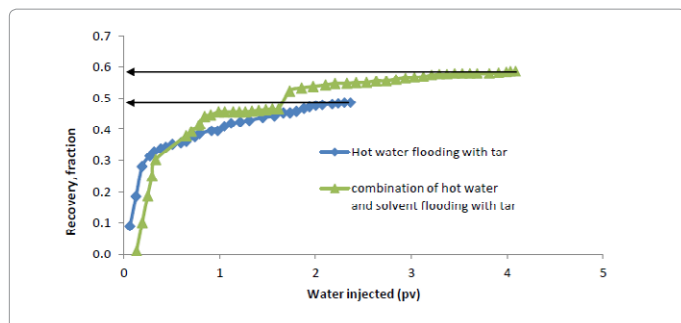


Figure 16: Comparing between recoveries when hot water or combination of hot water and solvent was injected for core A11.

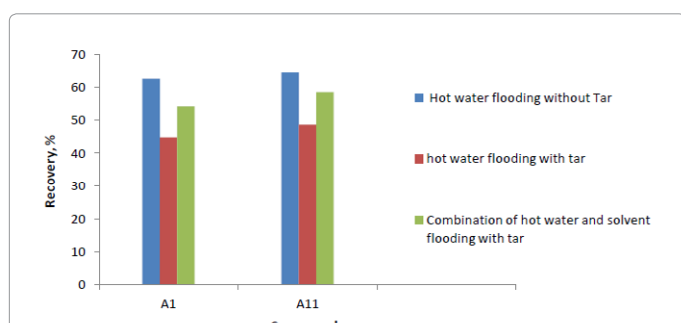


Figure 17: Comparison between recoveries with or without tar when hot water or combination of hot water and solvent was injected at different temperatures for cores A1 & A11.

| | Run 1 T = 60°C | Run 2 T=90°C | Run 3 With solvent |
|--------------|-------------------|-----------------|-----------------------|
| OZPV(cc) | 19.35 | 19.35 | 19.35 |
| TZPV(cc) | 7.39 | 7.39 | 8.23 |
| THZPV(cc) | 26.74 | 26.74 | 27.58 |
| Np(cc) | 6.82 | 8.65 | 10.45 |
| Water inject | 5PV | 5PV | 5PV |
| ORF (%) | 35.26 | 44.7 | 53 |

Table 4: The effect of water temperature and solvent on recovery factor for core A1.

| | Run 1 T=60°C | Run 2 T=90°C | Run 3 With solvent |
|--------------|--------------|--------------|--------------------|
| OZPV(cc) | 20.94 | 20.94 | 20.86 |
| TZPV(cc) | 6.74 | 6.74 | 6.83 |
| THZPV(cc) | 27.68 | 27.68 | 27.77 |
| Np(cc) | 8.27 | 10.17 | 12.23 |
| Water inject | 5PV | 5PV | 5PV |
| ORF (%) | 39.5 | 48.57 | 58.63 |

Table 5: The effect of water temperature and solvent on recovery factor for core A11.

| Reservoir method | Extractable Recovery (%) | Hypothetical Amount of Oil Recovered, BBls | Hypothetical Amount of Oil Recovered, BBls | Cost Method Recovery | Net Profit After Technology cost |
|--------------------------------------|--------------------------|--|--|----------------------|----------------------------------|
| Hot water/toluene Flooding. Core A1 | 53 | 313,026,766 | 21,911,873,634 | 60\$ | 3,130,267,662 |
| Hot water/toluene Flooding. Core A11 | 58.63 | 355,561,583 | 24,889,310,868 | 60\$ | 3,555,615,838 |

Table 6: Simple economic analysis for optimum recovery technique and its recoveries for a hypothetical tar-mat in Front of Oil (OOIP) case.

core A1 and 606,449,912 for core A11, because there is a tarmat layer as a barrier. If the oil price is assumed to be \$70 per barrel, then Table 6 shows that the maximum profit would be achieved using toluene recovery at 90°C because it recovers approximately 54% for core A1 and 85.63 for A11 of the extremely heavy oil; this recovery is well worth the hypothetical 60\$ cost of toluene injection see Table 7.

Error analysis

In all experimental studies, data collected are subject to experimental errors. Errors associated with the following quantities are discussed:

1. Porosity
2. Permeability
3. Saturation
4. Oil Recovery Factor (ORF)

The general mathematical expression for calculating the error is:

$$\Delta G = \Delta X_i \sum_i^n \left| \frac{\partial G}{\partial X_i} \right|$$

Where $G = F(X_1, X_2, X_3 \dots X_n)$

For example,

$$\Delta \phi = \phi \left[\frac{Evp}{vp} + \frac{Evb}{Vb} \right]$$

Conclusion

The following conclusions can be drawn based on the previous results and discussions:

- The oil recovery was reduced approximately 26% in the presence of tar.
- The oil recovery with hot-water flooding at T=90°C is substantially greater than flooding at T=60°C in the presence of tar.
- The oil recovery was increased approximately 9.2% when the water flooding Temperature was increased from 60°C to 90°C in the presence of tar.
- Toluene was a suitable solvent to dissolve and disperse the tar used for these experimental runs.
- The oil recovery with combined hot-water and solvent flooding was substantially larger than that with hot-water alone in the presence of tar.
- The oil recovery was increased by around 19% when the combination of hot water and solvent was used.
- The injection of a solvent slug followed by hot-water flooding disperses the tar layer and establishes adequate communication between the water and the oil zone.

| Sample | Evp | Evb | E ϕ | Eswi | EK | EORF |
|--------|-------|-------|----------|-------|--------|-------|
| A1 | 0.131 | 0.749 | 0.00265 | 0.051 | 15.465 | 0.02 |
| A2 | 0.131 | 0.699 | 0.00283 | 0.052 | 23.981 | 0.026 |
| A6 | 0.126 | 0.604 | 0.00308 | 0.063 | 62.03 | 0.027 |
| A7 | 0.125 | 0.555 | 0.00328 | 0.065 | 44.047 | 0.022 |
| A10 | 0.132 | 0.716 | 0.0028 | 0.05 | 44.118 | 0.025 |
| A11 | 0.133 | 0.751 | 0.00272 | 0.048 | 46.317 | 0.024 |

Table 7: Error Analysis of My Experiments data.

• Higher hydrocarbon recoveries are obtained with combined hot water and solvent flooding than with hot water alone.

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