A Study of Imbibition Phenomenon in Kirkuk Tertiary Reservoir

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Abstract

The aim of this paper is to study the imbibition phenomenon in Kirkuk tertiary reservoir (which is a dual-porosity system) and to isolate the individual effects of various parameters on imbibition's recovery. It also addresses the importance of characterizing the imbibition mechanism for analyzing the reservoir performance. A surrounded matrix block by the wetting phase is presented for the purpose of better understanding spontaneous imbibition characteristics. Numerous parametric studies have been performed within the scope of this research. Results showed that the temperature in Kirkuk tertiary reservoir crude oil have a substantial effect on the imbibition recovery mechanism, and the wettability index at the reservoir temperature is 0.24, which indicates that this formation has a very weak water-wet characteristics.

Introduction

Capillary imbibition is described as a spontaneous penetration of a wetting phase into a porous media while displacing a non-wetting phase by means of capillary pressure, e.g., water imbibing into an oil-saturated rock. Imbibition describes the rate of mass transfer between the rock and the fractures (Pashayev, 2004). It has been stated that the rate of imbibition increased with an increase in temperature due to reduction of oil-water interfacial tension, oil viscosity and water viscosity (Handy, 1960). Decrease in the viscosity ratio of oil and water due to increasing temperature result in oil being displaced more easily and the ultimate recovery being improved (Anderson, 1986). It is clear that the crude oil-brine-rock interactions are responsible for the dramatic increase in oil recovery with temperature increase rather than changes related to the rock properties alone (Tang & Morrow, 1997). Another study is performed by using a similar chalk core samples and the results were comparable. Changes in temperature, using refined oil are not verified in this study (Dangerfield & Brown, 1985). This study is focused on petro physical properties of Kirkuk tertiary reservoir (especially for Avana dome) because of sever changing in oil-water contacts. After the period of stopping productions (between years 1990 and 1996), injection operations lead to change the oil-water contacts, these changing in contacts are analyzed in this study.

Some Historical Facts of Kirkuk's Oil Field

Kirkuk field produces crude oil with 35^o API and 1.97% sulfur crude, although the API gravity and sulfur content both reportedly deteriorated sharply in the months just preceding the March/April 2003's war. Kirkuk's gravity, for instance, declined to around 32^o-33^o API, while sulfur content increased to above 2%.

Declining crude oil qualities and increasing the "water cut" (damaging intrusions of water into oil reservoirs) were likely the result of over-pumping. In addition the poor reservoir management practices during the years before the war including reinjection of excess fuel oil (as much as 1.5 billion barrels by one estimate), refinery residue, and gas-stripped oil may have seriously, even permanently, damaged Kirkuk formations. Among other problems, fuel oil reinjection has increased oil viscosity in Kirkuk reservoir, making it more difficult and expensive to get the oil out of the ground.

Imbibition Phenomenon in Kirkuk's Formation

Because of the fact that the Kirkuk tertiary reservoir consists of fractured rocks, where the porous blocks of rock matrix are surrounded by fracture voids, therefore the production of oil from such reservoir comes from two systems, one directly from the porous of rock matrix and two from the fractures. In both cases, the movement of oil from either matrix and/or the fractures creates empty spaces that are filled with water at oil/water contact and with gas at the gas-oil contact. The speed of rise being faster in fractures than in matrix leading to a situation in which blocks of matrix becomes submerged in water isolating them from direct contribution to production. The actual production from these blocks will then be by the very slow process of bubbling of oil drops from matrix pores to surrounding water to be collected at its surface where it is produced. This process called "imbibition" and is regarded as the only avenue of recovering oil trapped under water in the absence of direct production from the matrix itself by drilling through the matrix or perhaps by mining from it. In spite of being very slow and low efficiency, imbibition is a fact of life in reservoir performance and, therefore, an important phenomenon to be cognizant of in reservoir management.

Experimental Work

An Imbibition Cell is designed with thickness of 4 mm and dimensions of (70×30×40) cm covered with a temperature meter and 1500W heater inside it. Four glass containers are used in one cell to perform four tests in one time (see Fig.1) (Darwesh, 2009). Kirkuk dead oil (from Avana dome) with 33° API is used in the investigation. The viscosity and density are shown in (Figures 2, and 3) respectively. Formation water (brine) and Kirkuk core samples at reservoir temperature 138^{o} F are used. Before sand core samples are being used they are dried at an ambient temperature, and then dried also in an oven at 110°C for 3 days and cooled in a vacuum chamber. Core plugs are taken from the regions of oil-water contacts. The cores are cut to 2.54 cm in diameter and 2.54 cm in length. The air permeabilities are varying from 0.1 to 112 md and the porosity is ranged from 4% to 24.5%, (see Table 1). A traditional toluene Dean-Stark extraction method was used to clean the core samples.

Fig.1a

Fig.1b

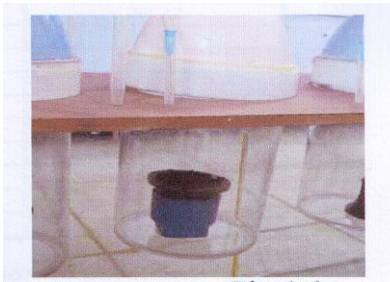

Fig.1c

Fig. 1: Spontaneous imbibition cell

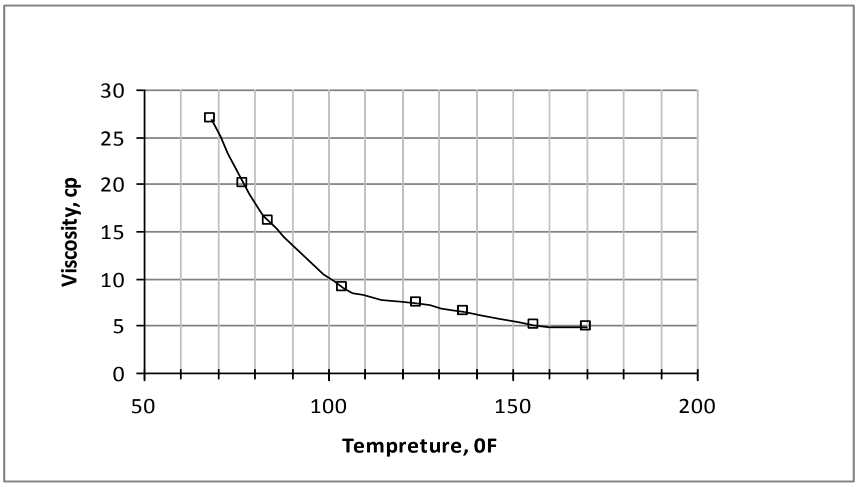

Fig. 2: Kirkuk crude oil viscosity behavior with temperature

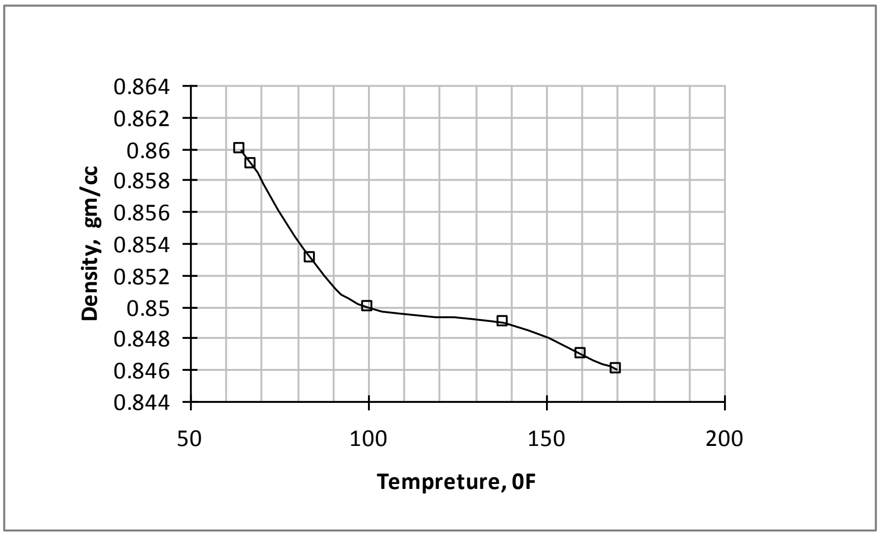

Fig. 3: Kirkuk crude oil density behavior with temperature

Table 1: The physical properties of the reservoir core samples

Core No.	Well No.	Depth ft RTKB	Diameter cm	Length cm	Kair md	Grain density gm/cc	Pore Volume cc	Porosity %	Swi %
1	K116	2222-2223	2.54	2.54	0.15	2.96	0.16387	4.0	31.20
2	K116	2222-2223	2.54	2.54	112	2.80	0.544869	13.3	40.56
3	K119	2733-2746	2.54	2.54	0.1	2.89	0.196644	4.8	32.30
4	K119	2733-2746	2.54	2.54	0.1	2.80	0.315450	7.7	33.10
5	K144	2314	2.54	2.54	37	2.87	1.003707	24.5	39.96
6	K144	2314	2.54	2.54	28	2.87	0.98322	24.0	38.45
7	K149	2177	2.54	2.54	0.25	2.81	0.782482	19.1	31.75
8	K149	2166	2.54	2.54	0.97	2.80	0.782482	19.1	32.69
9	K40	2422	2.54	2.54	0.85	2.77	0.96274	23.5	35.12
10	K40	2427	2.54	2.54	35	2.76	0.925869	22.6	34.44

Results and Discussion

1. (Figure 4) presents the cumulative oil production from the core sample as a function of time; the portion of the curve of oil recovery corresponding to the early time periods represents the maximum rate of imbibition. During this process (spontaneous imbibition) more oil is recovered using a homogeneous and high permeability porous medium, and the deviation of oil recovery curve is caused by the imbibition rate slowing down. The imbibition rate slows down because of that the all major channels of flow are already filled. Later, the curve completely bends over and the rate of imbibition is drastically reduced. At this stage, a very slow change in water saturation within the time is observed in the core. The amount of oil produced is used for water wettability index (I_W) determination.

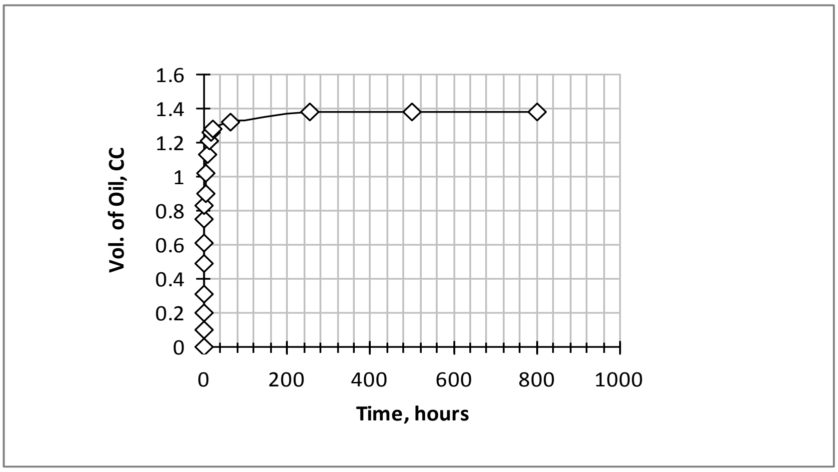

Fig. 4: Cumulative oil production after spontaneous imbibition

2. During the experiments; it is found that the change in temperature from ambient to reservoir conditions causes a dramatic increase in the rate of spontaneous imbibition (oil recovery is expressed as a percent of Initial Oil Inplace – IOIP), which consequently improve the recovery. Besides of that the temperature effects are very critical on the imbibition rates, as shown in (Fig.5) the results obtained from the experiments of this study are shown good agreement with the results of some authors (Anderson, 1986; Hing & Mungan, 1973; Hjelmeland & Larrondo, 1986 and Cuiec *et al.*, 1994).

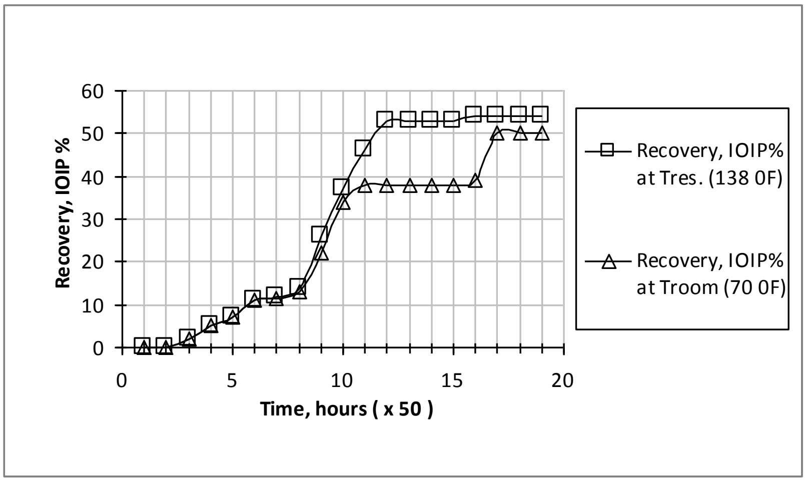

Fig. 5: Effect of changing temperature on the rate of imbibition recovery

3. Effect of temperature on spontaneous imbibition: by using the volumetric method, four core samples of Kirkuk formation are used, two of these cores (core No.1 and core No.2) are prepared for spontaneous imbibition under reservoir temperature 138^{o}F, and the other two cores (core No.3 and core No.4) are prepared for spontaneous imbibition under ambient conditions 70^{o} F. All cores are established at the same initial water saturation of 34%. In (Fig.6) the results demonstrate that during the process of brine imbibition into the low permeability core (core No.1) the water [at reservoir (elevated) temperature] is imbibed by the rock faster than that at the room temperature, and then good oil production is indicated. The ultimate recovery is also affected by the temperature; with increasing temperature higher ultimate recovery is obtained, this increasing of recovery was with remaining all other parameters constant (like time, aging, and rate of imbibition).

These results are compatible with some previous studies (Handy, 1960; Anderson, 1986; Tang & Morrow, 1997; Reis & Cil, 2000 and Babadagli, 2002). Based on the surface physical chemistry (Anderson, 1986), an increase in temperature tends to increase the solubility of wettability-altering compounds and desorbs from the surface.

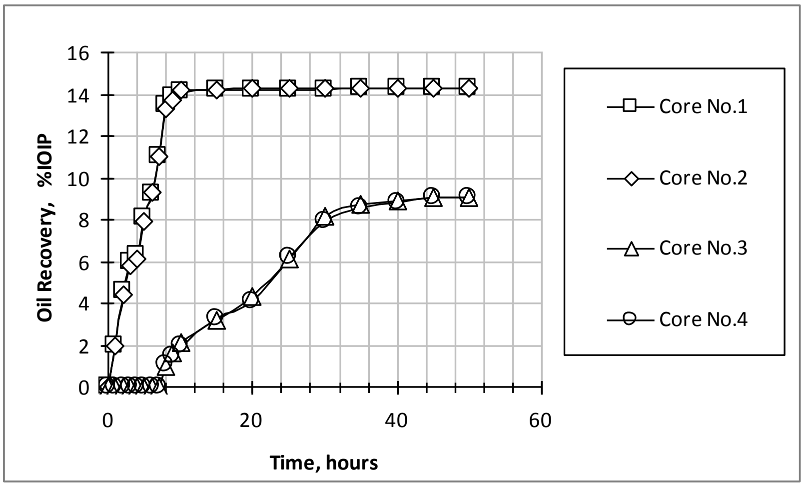

Fig. 6: Effect of temperature on ultimate imbibition recovery, Core No. 1, and 2 are at 138^{o} F, Core No. 3 and 4 are at 70^{o} F

4. Effect of aging time: the effect of aging commencement of the imbibition process is investigated by using 10 cores aged in oil at 138^{o} F. The aging times varied from 0 to 30 days, and for comparison two cores are not aged in oil, see (Table 2). Oil recoveries from spontaneous imbibition tests are plotted with time in hours. It can be concluded that the rate of imbibition of cores (without aging) are faster than for the aged cores, see (Fig.7). Slightly different imbibition rates at the beginning of the imbibition test are observed for the cores aged from seven to 30 days. However, oil recovery after 21 days of imbibition decreased substantially from 15% to 10% IOIP with increase in aging time from no aging to 30 days of aging. A more representative reservoir condition is obtained when the core is aged before the imbibition test under reservoir temperature. The effects of aging become less important to the recovery mechanism if forced imbibition or brine displacement takes place after spontaneous imbibition. The total oil recoveries appear to remain constant for core aged more than seven days.

Table 2: The physical properties of the reservoir core samples

Recording time, hours	IOIP% for all cores									
	No aging		7 days aging		14 days aging		21 days aging		30 days aging	
	Core1	Core2	Core3	Core4	Core5	Core6	Core7	Core8	Core9	Core10
0.1	0	0	0	0	0	0	0	0	0	0
0.5	2.1	2.4	0	0	0	0	0	0	0	0
1	4.5	4.5	1	1.1	0.9	1.1	0.2	0.3	0.5	0.4
2	6	6.1	2.4	2.3	1.9	1.9	1.3	1.81	1.4	1.5
3	8.9	8.9	5	5.02	4.9	4.6	1.9	1.95	3.8	3.85
4	9.4	9.4	5	5.1	4.9	4.92	2.5	2.6	4.9	4.6
7	11.1	11.3	7.1	7.4	5.1	5.2	5.4	5.3	6	6.2
10	12.7	12.3	7.7	7.7	6.5	6.4	5.8	5.7	6.7	6.5
20	13.3	13.4	9.5	9.3	8.5	8.6	7.1	7.2	7.9	7.8
30	14.3	14.2	13	13.1	10.3	10.1	7.9	8	8.3	8.2
50	14.3	14.2	13.75	13.8	12.9	12.8	9	9.2	9.1	9.1
100	14.3	14.2	13.75	13.8	12.9	12.8	10	10.1	9.5	9.6
500	14.3	14.2	13.75	13.8	12.9	12.8	10	10.1	9.6	9.6
1000	14.3	14.2	13.75	13.8	12.9	12.8	10	10.1	9.6	9.6

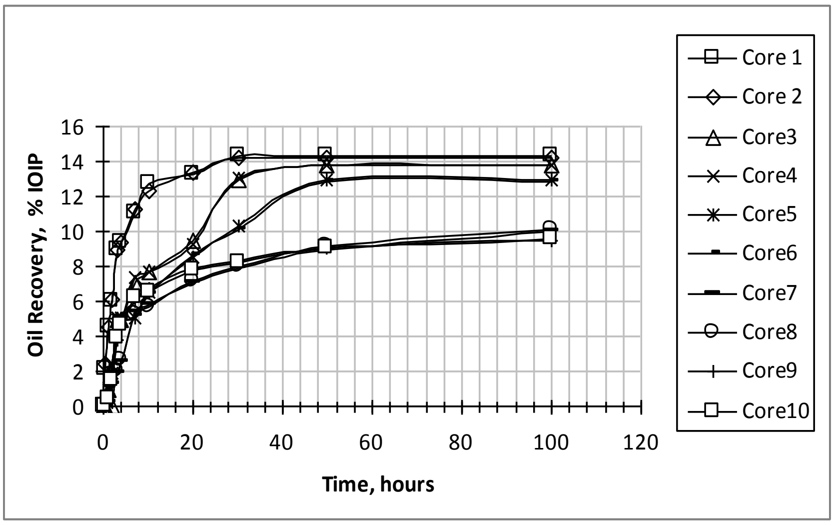

Fig. 7: The effect of aging time on imbibition recoveries for 10 core samples at reservoir temperature 138^o F with aging time varied between 0 to 30 days

5. Effect of temperature on brine displacement: after the implementation of the imbibition process at the reservoir temperature, the total recoveries of cores (that are good aged for more than seven days and that are flooded by brine at room temperature) are remained constant at an average of about 35% IOIP. When the brine displacements are performed at the reservoir temperature, the total oil recoveries are improved to 65% IOIP (for the cores with and without aging in oil). It is found that the increasing in

temperature degrees during the brine displacement process will increases the displacement recovery, thus the total recovery is increased. Also a total recovery of 44% is obtained after the brine imbibition and displacement at the room temperature is implemented. Under these conditions there were no aging effects for the cores tested.

6. Wettability index can be express as:

$$I_w = \frac{R_{imb.}}{R_{imb.} + R_{bf.}}$$

Where R_{imb} is oil recovery by imbibition and R_{bf} is oil recovery by brine displacement flooding. A high index indicates more water-wet system while the lower index indicates less water-wet rocks. The wettability index of about 0.35 for brine imbibition at reservoir temperatures (with brine displacement at room temperature) is obtained. Wettability index of about 0.24 for brine imbibition and displacement both at reservoir temperature is obtained. As the temperature rises, the viscosity ratio of oil to brine is decreased. The decreasing in viscosity at higher temperatures was much greater for oil than that for brine. Thus, the increase in temperature can
++ in a substantial decrease in viscosity ratio of oil to brine.

7. Heterogeneity in rock properties: Initial water saturations for the cores used are varied from 32% to 43% which are not providing a great enough difference to affect the recovery obtained. It can be concluded that the increase in initial water saturations will decrease the capillary pressures; consequently the ultimate oil recovery is decreased. Permeabilities of the cores used are ranging between 0.1 to 112.7 md. Oil recoveries by the imbibition phenomenon are plotted against the permeabilities as shown in (Fig. 8). The results show that the imbibition recoveries are slightly affected by the core heterogeneities.

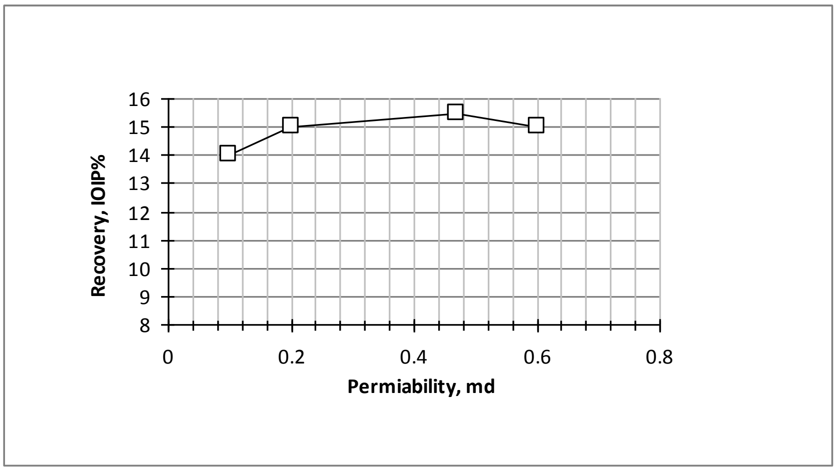

Fig. 8a: Brine imbibition and displacement at reservoir temperature

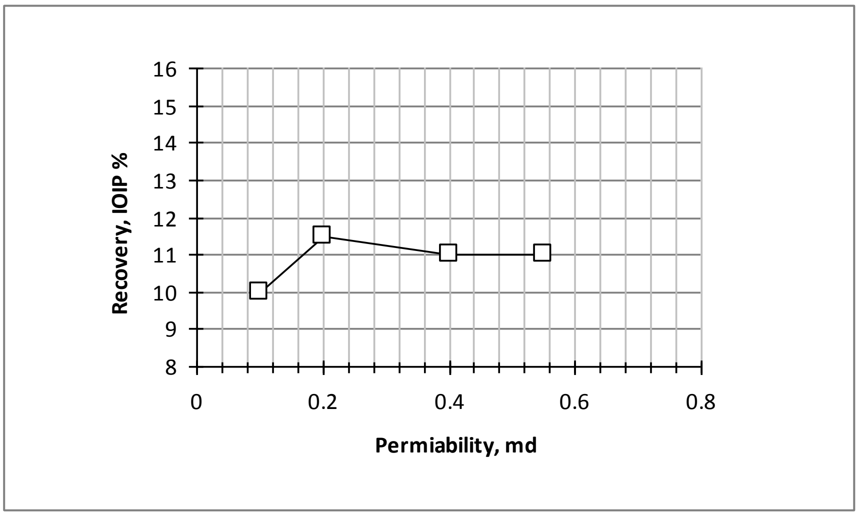

Fig. 8b: Brine imbibition and displacement at room temperature

Conclusions

1. Low permeability Kirkuk cores are imbibe water more readily at higher temperatures (i.e. reservoir temperatures), consequently; the ultimate recoveries were higher at these greater temperatures.
2. The oil/brine/rock interactions are responsible for dramatic increase in oil recovery with temperature rather than the changes in rock properties alone.
3. More representative reservoir condition is obtained when the core is aged at reservoir conditions before the imbibition test is performed.
4. Oil recovery due to the imbibition process is decreased from 15% of IOIP at no aging to 10% of IOIP after 30 days of aging.
5. Aging becomes less important to recovery, if forced imbibition or displacement is to be used.
6. Wettability index at reservoir temperature is 0.24, which indicates that Kirkuk group is a very weak water-wet rock.
7. Higher permeability increases the imbibition recovery slightly; the permeability range used in these experiments does not affect the total recovery.

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دراسة ظاهرة الإرتشاف في مكمن كركوك الثلاثي

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الخلاصة

الهدف من هذا البحث هو دراسة ظاهرة الإرتشاف في مكمن كركوك الثلاثي (و الذي هو عبارة عن نظام ثنائي – المسامية) و لعزل العوامل المختلفة و المترتبة على إستخلاص الإرتشاف، و كذلك البحث في أهمية صفات ميكانيكية الإرتشاف لتحليل أدائية المكمن، و لغرض الفهم الأحسن لصفات الإرتشاف التلقائي تم عرض مقطع مصفوفة محاط بالطور المرطِب. و تم دراسة كم هائل من العوامل المتغيرة في ثنايا هذا البحث. تبين من النتائج بأن درجة حرارة خام مكمن كركوك الثلاثي لها تأثير جوهري على ميكانيكية إستخلاص الإرتشاف، و دليل الترطيب في درجة حرارة المكمن يساوي ٠,٢٤ و الذي يشير إلى أن هذا التكوين يمتلك صفات ضعيفة جداً للترطيب بالماء.