Journal of Engg. Research Vol. 7 No. (2) June 2019 pp. 366-377

Experimental investigation of heavy oil recovery by hot water flooding followed by steam flooding for lower Fars reservoir, Kuwait

Yousef S. Kh. S. Hashem*, Hothama O. Alwaqyan** and Adel M. Elsharkawy

Petroleum Engineering Department, College of Engineering & Petroleum, Kuwait University, P.O. Box 5969, Safat 13060, Kuwait
***Quality Control Unit, ministry of Public Works, Kuwait*
**Corresponding Author: y.hashem@ku.edu.kw*

ABSTRACT

In this study, hot water and steam flooding tests were conducted on eight unconsolidated sandstone core samples from Lower Fars. The hot water flooding tests were conducted at 60°C and 80°C followed by steam flooding at 153°C for the first four cores (pre-heated cores), whereas a direct steam flooding at 153°C was conducted on the last four cores. Both horizontal and vertical core flooding displacement tests were conducted.

The main objective of this work is to evaluate the efficiency of heavy oil recovery from Lower Fars reservoir using hot water flooding at various temperatures followed by steam flooding and direct steam flooding. The results of these experiments can be used to determine the optimum recovery method for Lower Fars reservoir. The average cumulative oil recovery when the cores are pre-heated for vertical setting was 77.5% compared to 74.0% for direct steam flooding. In addition, the average cumulative oil recovery when the core is pre-heated for horizontal setting was 58.4% compared to 52.0% for direct steam flooding.

Keywords: Heavy oil, hot water, steam flooding, lower Fars.

INTRODUCTION

Thermal recovery methods have been the most commonly applied to heavy oil. Kuwait Oil Company (KOC) has a strategic plan to increase its oil production to reach 4 MMSTB per day. To achieve such a goal, it is important to develop heavy oil reservoirs. Lower Fars is the largest heavy oil reservoir in Kuwait with an approximate reserve of 13 billion barrels[1].

Most of heavy oil production comes from sandstone formations, but heavy oil can also be found in carbonate formations, which are more complex than sandstone formations because of the presence of fractures and vugs[2]. The world's largest heavy oil reserves are found in Venezuela, Canada, Russia, Brazil, Alaska, and China. In Canada, open-pit mining of shallow oil sands contributes to approximately 50% of the nation's heavy oil production. Unlike the oil sands of Canada, heavy oil resources in the Middle East are often found in carbonate reservoirs. The heterogeneous nature of these rocks presents several challenges when designing production programs.

This study will evaluate the efficiency of heavy oil recovery from Lower Fars reservoir using hot water flooding at various temperatures followed by steam flooding and direct steam flooding. In addition, the study will evaluate the effect of gravity on heavy oil recovery by hot water flooding followed by steam flooding. Finally, because only small cores were available to conduct these tests, the heavy oil recovery plot will be evaluated for repeated results from different cores to check for the reliability of using small cores for core-flood tests.

The experimental oil recovery from steam flooding done by Bursell and Pittman[3] concluded that the higher the oil viscosity, the lower the recovery under identical conditions. Sun Chuansheng et al.[4] carried out laboratory experiments of hot water injection followed by steam injection and conducted numerical simulations. They found that the initial oil saturation at the beginning of the steam flood is directly proportional to the oil displacement efficiency.

The results of laboratory studies of Willman et al.[5] showed that high pressure and temperature-saturated steam recover more oil effectively than cold or hot water. Hong[6] numerical simulation study results also showed that no single steam quality or injection rate can be optimum for all reservoirs. The experimental results conducted by Butler[7] showed that the oil recovery by steam injection is significantly higher than recovery by hot water injection. It is concluded that the effects of steam distillation, gas-drive, and solvent extraction contribute to higher oil recovery during steam injection. Bing-Bing Han et al.[8] concluded that injection temperature and rate of hot water had an effect on reservoir oil recovery through influencing temperature field.

To implement any EOR method, such as steam flooding, a complete, detailed study is required. Barage et al.[9] reported an inverted five-spot pattern steam pilot test, which was conducted in the Wafra dolomite reservoir. Steam was continuously injected at a rate of 500 barrels per day, cold water equivalents, with a pressure of 600 psig and a temperature of 489˚F. A breakthrough occurred in three producers after approximately ten months of continuous steam injection. Several operational and design changes were applied throughout the two-year period to minimize corrosion/erosion effects. The two-year pilot test helped evaluate reservoir response to steam flooding. It also helped explore the variation of response due to rock/fluid interactions over time. In addition, it assisted in the evaluation of well productivity, well equipment, and well construction. Eventually this pilot test helped in decision-making and provided lessons for the next phase of the project.

LOWER FARS (SOUTH RATQA)

Lower Fars is the largest heavy oil reservoir in Kuwait[10] as shown in Figure 1 with an approximate reserve of 13 billion barrels. Lower Fars is located in North Kuwait. It is a high unconsolidated sandstone reservoir with a depth of approximately 300-600 ft, a permeability of 500-8000 md, a porosity of 30-35%, a reservoir pressure of 230-250 psia, and a temperature of 90˚F. The oil saturation in Lower Fars is approximately 30-80% with a viscosity range of 100-1500 cp depending on the depth. The API gravity is 12-18^{o} with no free water zone for most parts of the reservoir. Recently, cyclic steam stimulation (CSS) was conducted in 6 wells. There were two CSS pilot studies conducted on Lower Fars in the 1980s, each with four wells. In the first pilot study, initiated in 1982, the wells were 68 feet of net pay, injected with steam of 76% quality (423-441˚F) at rates of 965-1250 barrels of water equivalents per day for 15-30 days, and then soaked for approximately 3-9 days, followed by a production time of four years with a saturation oil ratio (SOR) of less than 0.15 and water-to-oil ratios of less than 0.25 cumulative. The second pilot was conducted on 1986; the wells were 48 feet net pay, injected with steam of 75% quality (421-438˚F) at rates of 652-837 barrels of water equivalents per day for 20-28 days, and then soaked for approximately 20-28 days, leading to the production of 42-65 M barrel, with an SOR of 0.35. Lower Fars responded ideally to the thermal stimulation, and the production ratios suggest that it is not connected to an active water aquifer. The development of the field was stopped after the second pilot in 1986 and resumed again in 2012.

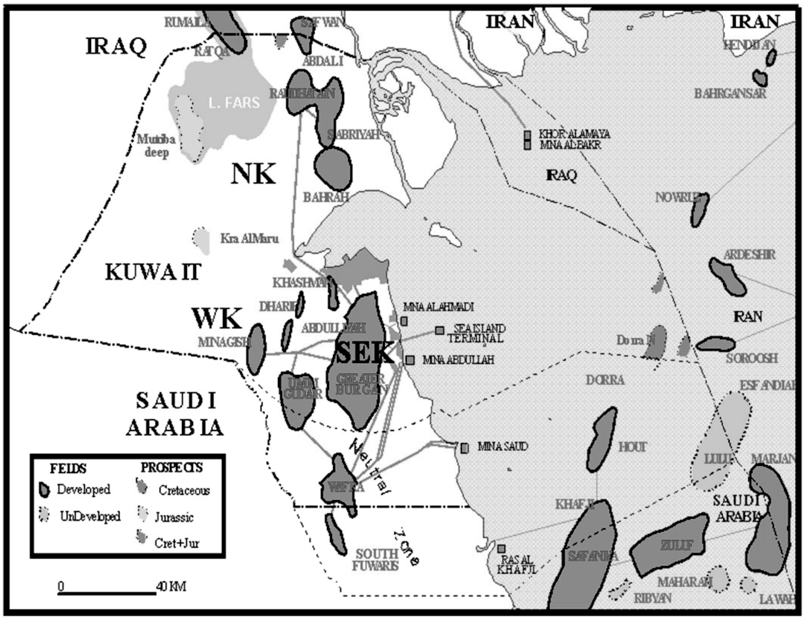

Fig. 1. Kuwait map and field location.

LABORATORY WORK

A heavy oil sample was collected directly from a producing well[11]. The oil sample was tested for viscosity, density, and composition at atmospheric pressure and varying temperatures. The results of the viscosity and density tests at various temperatures are listed in Table 1. The measured molecular weight of the heavy crude oil was 343 gm/mol. Hydrocarbon Analysis (DHA) software was used to provide automatic identification of the components up to C26+. Table 2 shows the details of the components of the heavy oil used in this work. The measured viscosity as a function of temperature is shown in Figure 2. This figure indicates that oil viscosity can be reduced from 660 cp at 15°C to nearly 10 cp by heating the oil to 100°C. Preserved core plug samples were collected from Lower Fars at different depths. All cores were highly unconsolidated sandstone. The cores had been frozen and then preserved by a wax coating method. The freezing process involved applying liquid nitrogen to the core before removing it from the coring barrel to prevent any collapse or damage while handling the core, and then, dry ice was used throughout the preservation period. The wax coating preservation method places a Teflon coating around the core, double mesh on both sides of the core, and, finally, a yellow wax coating. This preservation method had been applied to the cores at the well site and can safely protect the cores for a long period of time.

Table 1. Lower Fars viscosity and density at various temperatures.

Temperature (° C)	μ (cp)	ν (c.st)	ρ (gm/cm^3)
15	653.81	682.87	0.9575
20	445.38	466.75	0.9541
30	223.11	235.61	0.9453
40	123.46	131.04	0.9411
50	73.462	78.619	0.9343
60	46.602	50.249	0.9274
70	31.457	24.06	0.9217
80	21.832	23.881	0.9142
90	15.905	17.514	0.9078
100	9.891	11.053	0.8959

Table 2. Lower Fars fluid properties and molecular composition.

Component	Mole %	Wt. %	MW	Density
Iso-Butane	0.417	0.073	58.124	0.562
n –Butane	0.878	0.154	58.124	0.583
Neo- Pentane	0.000	0.000	72.150	0.624
Iso- Pentane	1.546	0.336	72.150	0.630
n -Pentane	0.724	0.157	72.150	0.685
pseudo C6	3.205	0.831	86.177	0.668
pseudo C7	3.649	1.058	96.326	0.715
pseudo C8	4.716	1.558	109.742	0.740
pseudo C9	3.912	1.470	124.881	0.757
pseudo C10	4.439	1.804	135.035	0.796
pseudo C11	3.182	1.376	143.671	0.821
pseudo C12	2.470	1.153	155.153	0.830
pseudo C13	2.087	1.074	171.084	0.831
pseudo C14	1.643	0.927	187.546	0.837
pseudo C15	1.424	0.829	193.562	0.852
pseudo C16	1.099	0.682	205.996	0.839
pseudo C17	0.693	0.482	231.332	0.818
pseudo C18	0.673	0.477	235.549	0.830
pseudo C19	0.553	0.423	254.377	0.824
pseudo C20	0.449	0.360	266.429	0.835
pseudo C21	0.289	0.258	296.030	0.810
pseudo C22	0.303	0.283	310.009	0.811
pseudo C23	0.208	0.203	324.031	0.810
pseudo C24	0.199	0.202	338.041	0.811
pseudo C25	0.187	0.198	352.131	0.810
pseudo C26+	61.055	83.631	455.151	0.995
Total	100.000			

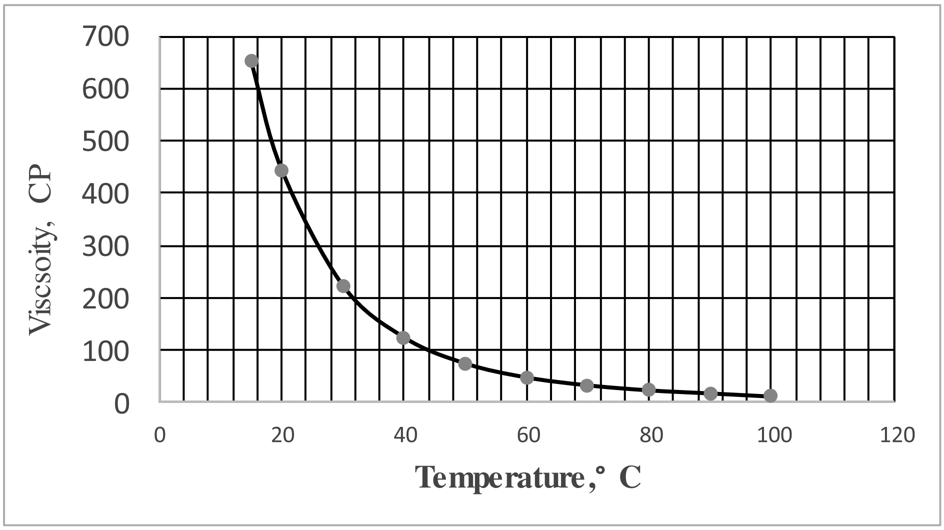

Fig. 2. Viscosity versus temperature for Lower Fars.

The preparation of the frozen core sample started with cutting a cross section from the wax sealing of the core and then the wax around the core, but the aluminum sealing with the double mesh was maintained to prevent core collapse. As the cores are highly unconsolidated sandstone, as shown in Figure 3, routine core analysis was not conducted, and the cores were not cleaned. After core preparation, the frozen core was placed inside a black rubber barrel and inserted into a core holder to start the flooding process. The core holder for cores 1, 2, 5, and 6 was placed vertically to observe the effect of gravity on the amount of oil produced. For cores 3, 4, 7, and 8 the core holder was placed horizontally.

Fig. 3. Highly unconsolidated core.

HOT WATER FLOODING SETUP

The experimental setup for hot water flooding, shown in Figure 4, has a single cylinder water pump. First, water was poured into the pump cylinder tank, which was connected to the main power supply. The single cylinder water pump was connected to the core holder via an injection pipe. The injection pipe was partially attached to the heating rod and the thermostat rod of the temperature regulator, and this part of the pipe was isolated to avoid heat loss to the atmosphere. The core holder was also connected to a hydrogen cylinder to apply a confining pressure of 220 psi to the core sample, to resemble the reservoir pressure. The output pipe was connected to the electrical thermometer to measure the outlet temperature. At the end of the outlet pipe, a graduated cylinder was used to collect the output fluids. Water at 60˚C was injected into the core at a rate of 1 cc/min until no more oil was produced. Then, the collected oil was measured to calculate the oil recovery at this stage. The water temperature was then increased to 80˚C, and the water was then injected into the same core with the same injection rate of 1 cc/min until no more oil was produced. The produced oil was collected and measured to calculate the incremental recovery of oil for the second stage. The inlet temperature of the first and second processes was controlled and measured by temperature regulator.

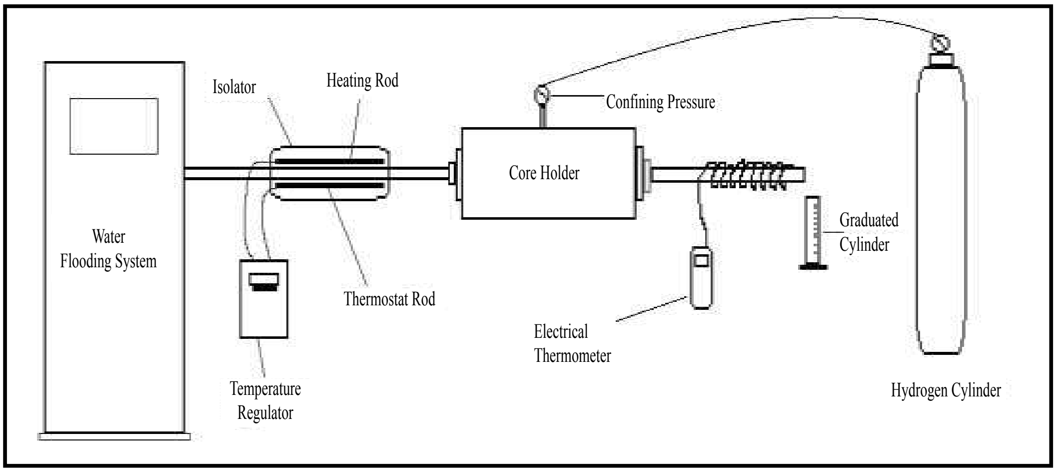

Fig. 4. Hot water setup.

STEAM FLOODING SETUP

After flooding the core with hot water at 60°C followed by 80°C, as previously explained, the core was flooded with steam. The steam flooding setup is shown in Figure 5. The water was fed into the steam generator by a feed water pump. The steam generator pressure gauge was set to 60 psig, which indicates the steam pressure. The steam pressure setting allows the determination of the steam temperature using pressure-temperature steam tables. The steam temperature at 60 psig is 307.3 °F, or 152.9°C. The produced steam was then injected into the core until no more oil was produced. After each stage, the produced oil was collected in a graduated cylinder containing three drops of de-emulsifier to prevent the formation of oil droplets in the oil water system. During all stages, certain parameters were monitored, including inlet temperature, outlet temperature, injection rate, injection pressure, and injected water volume. Table 3 describes the core setting and the type of injected fluid for all experiments.

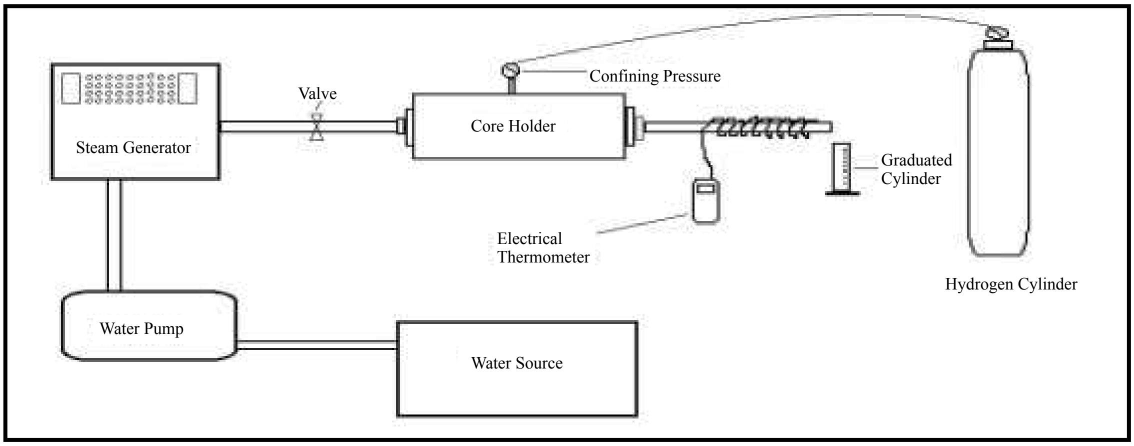

Fig. 5. Steam flooding setup.

Table 3. Schemes of experimental runs.

Core No.	Core Setting	Temperature of Hot Water injected, °C		Temperature of Steam injected, °C
1 & 2	Vertical	60	80	153
3 & 4	Horizontal	60	80	153
5 & 6	Vertical			153
7 & 8	Horizontal			153

RESULTS

The porosity and water saturation given for each core sample were obtained from logs because of the unconsolidated nature of the core samples. The weight and length of the core samples before mounting were directly measured before applying the Teflon and wax coats. Table 4 shows the cores' length, area, bulk volume, pore volume, and oil in place. Eight core samples were collected from KOC. Four cores were used to conduct the experimental procedure of hot water flooding followed by steam flooding. Cores 1 and 2 were placed vertically to account for gravity effect, and cores 3 and 4 were placed horizontally. The last four cores were used for direct steam flooding. Cores 5 and 6 were placed vertically and cores 7 and 8 were placed horizontally.

Table 4. Core properties and OOIP.

Core No.	Depth (ft)	Porosity (%)	S_w (%)	Length (cm)	Diameter (cm)	Area (cc)	BV (cc)	PV (cc)	OOIP (cc)
1	702.15	36	28	6.055	3.613	10.25	62.08	22.35	15.47
2	710.75	37	25	5.790	3.665	10.55	61.08	22.60	16.30
3	715.65	36	25	5.272	3.620	10.29	54.26	19.53	14.09
4	723.45	38	34	6.070	3.563	9.97	60.52	22.99	14.59
5	660.95	36	19	5.550	3.700	10.75	59.67	21.48	17.06
6	645.05	36	30	6.400	3.700	10.75	68.81	24.77	17.00
7	625.15	36	29	6.210	3.570	10.01	62.16	22.38	16.57
8	678.95	36	23	5.500	3.650	10.46	57.55	20.72	14.42

The produced oil and water formed an emulsion. In addition, oil droplets were formed on the top and within the produced water, as well as around the inner cylinder. To break down this emulsion, a few drops of a de-emulsifier were added to the graduated cylinder. After finishing the flooding process, the graduated cylinders filled with oil and water were treated further to separate the oil from the water. First, the cylinders were placed on a hot water ultra-sonic bath for some time. The emulsion was heated to reduce the oil viscosity, and the ultra-sonic device created vibrations, to move the oil droplets to the surface to form a clear layer of oil. This step took 2-5 days to ensure most of the oil droplets were separated from the cylinder wall and had risen to form a thin film of oil. This type of emulsion is a tight emulsion which is difficult to break. After the ultra-sonic treatment, 100 ml of the oil and water mixture was extracted from each cylinder by a syringe. This 100 ml of oil and water was placed in a test tube. The test tube was centrifuged to separate the droplets of oil from the water because small scale droplets are more easily broken. Then, the amount of oil was directly measured in the test tube. This measurement of oil represents a volume percentage of oil as the direct oil volume measured at this step was from the 100 ml of the total mixture produced. Finally, the oil volume percentage was multiplied by the total amount of oil and water produced to estimate the exact amount of oil produced for each flooding process. The results of cumulative oil recovery percent are shown in Table 5 for cores number 1 to 4 for hot water flooding followed by steam flooding and cores 5 to 8 for direct steam flooding. For vertical setting, the ultimate oil recovery from cores 1 and 2 was 65.4% and 89.6%, respectively. For horizontal setting, the ultimate oil recovery from cores 3 and 4 were 48.9% and 67.9%, respectively. The average cumulative oil recovery for vertical setting cores 1 and 2 (77.5%) was higher than that for horizontal setting cores 3 and 4 (58.4%). This is due to gravity effect in vertical setting and to steam over-ride in horizontal setting, which makes steam/oil breakthrough early. The results of oil recovery using both vertical and horizontal settings of hot water followed by steam flooding are shown in Figure 6. This Figure indicates that the oil recovery curves for cores 1 and 2 have the same production trend. Similarly, cores 3 and 4 showed a similar production trend. The oil recovery percentages at each flooding stage of the hot water followed by steam flooding are shown in Figure 7. This Figure shows that core 2 has the highest oil recovery percent among the first 4 cores because it has the highest OIP as indicated in table 4 and also due to gravity effect in vertical setting.

Table 5. Oil recovery and cumulative oil recovery under various conditions for all cores.

Core No.	Temperature (°c)	Oil Recovery (cc)	Cumulative Oil Recovery (cc)	Cumulative Recovery (%)
1	60	3.5	3.5	22.6
	80	2.0	5.5	35.5
	153	4.6	10.2	65.4
2	60	5.1	5.1	31.3
	80	4.2	9.3	57.0
	153	5.3	14.6	89.6
3	60	3.2	3.2	22.7
	80	1.7	4.9	34.8
	153	2	6.9	48.9
4	60	4.3	4.3	29.4
	80	3.2	7.5	51.4
	153	2.3	9.8	67.2
5	153	10.67	10.67	62.53
6	153	14.53	14.53	85.47
7	153	7.30	7.30	44.06
8	153	8.63	8.63	59.84

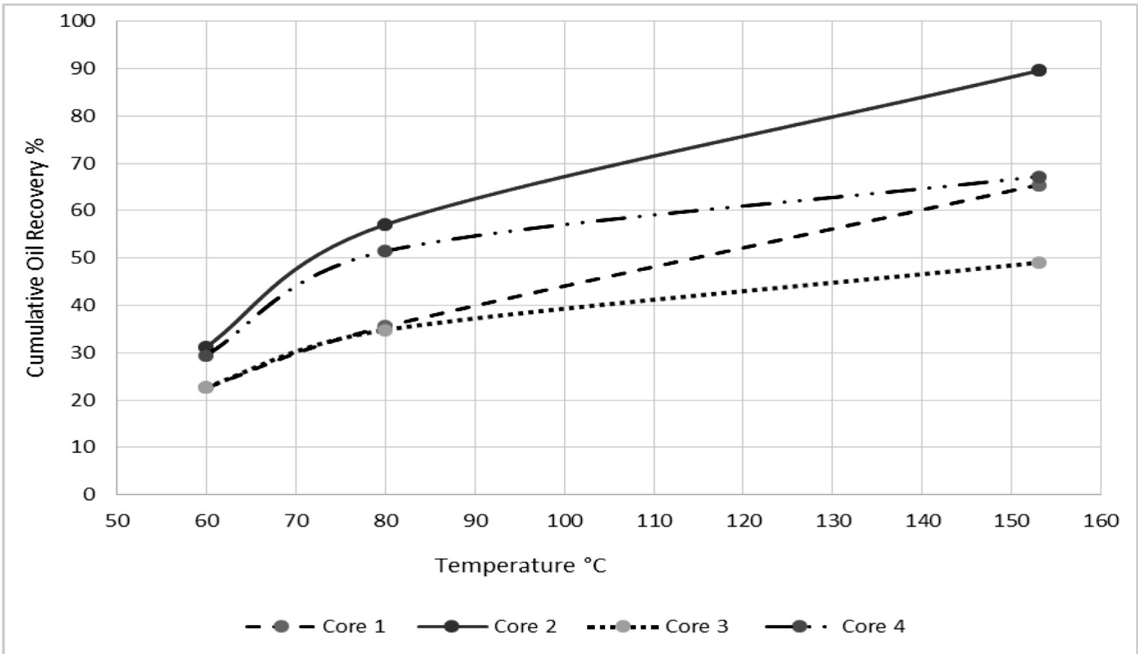

Fig. 6. Cumulative oil recovery versus temperature for vertical (1&2) and horizontal (3&4) flooding with hot water at 60°C and 80°C followed by steam flooding at 153°C.

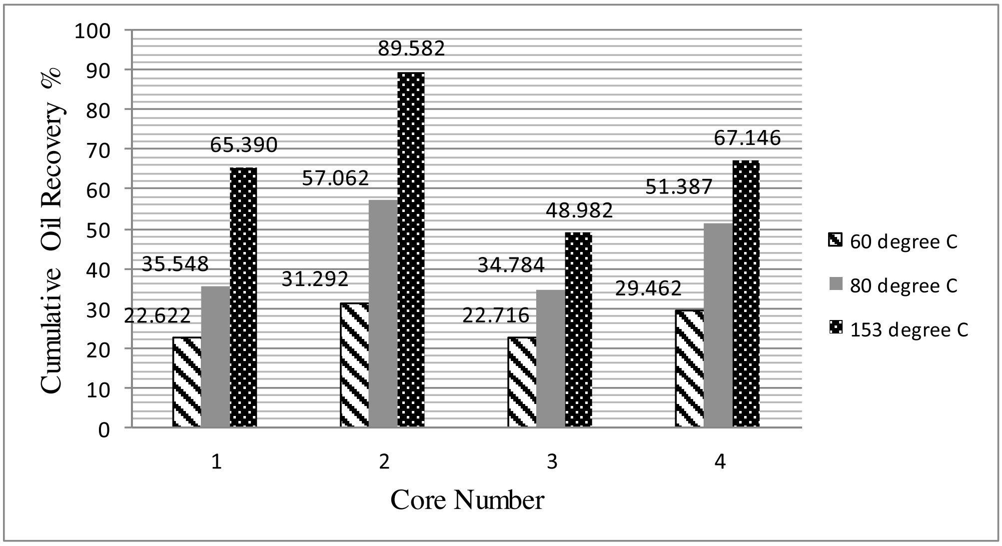

Fig. 7. Cumulative oil recovery at different temperatures versus cores in vertical setting (1 & 2) and horizontal setting (3 & 4).

For direct steam flooding, the ultimate oil recovery in vertical setting from cores 5 and 6 was 62.5% and 85.5%, respectively. For horizontal setting, the ultimate oil recovery from cores 7 and 8 was 44.1% and 59.8%, respectively. The average cumulative oil recovery for vertical setting cores 5 and 6 (74.0%) was higher than that for horizontal setting cores 7 and 8 (52.0%).

The results of oil recovery using both vertical and horizontal settings for direct steam flooding are shown in Figure 8. The average cumulative oil recovery when the core is pre-heated for vertical setting (cores 1 and 2) was 77.5% compared to 74.0 % for direct steam flooding (cores 5 and 6). In addition, the average cumulative oil recovery when the core is pre-heated for horizontal setting (cores 3 and 4) was 58.4% compared to 52.0% for direct steam flooding (cores 7 and 8) as shown in Figure 9.

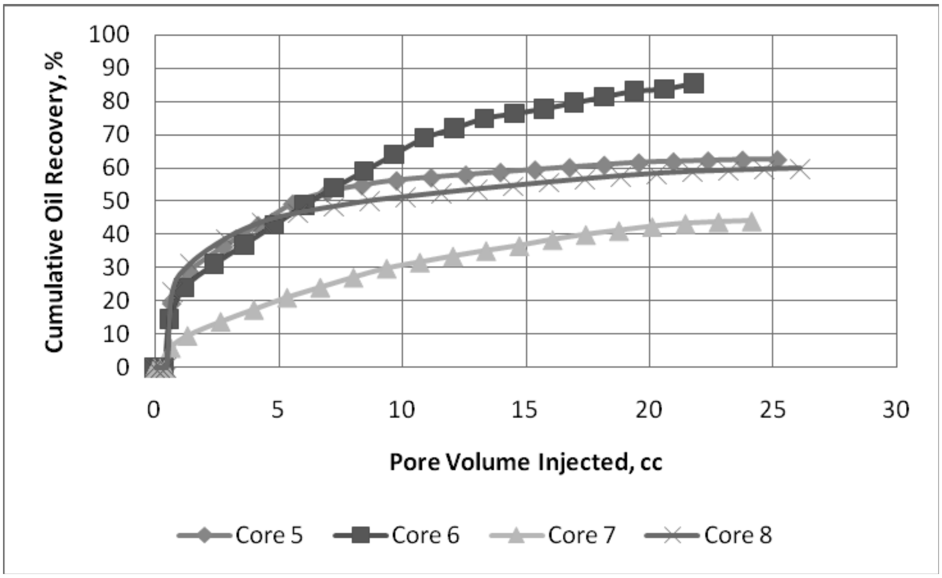

Fig. 8. Cumulative oil recovery versus pore volume injected for direct steam flooding in vertical setting (5 & 6) and horizontal setting (7 & 8).

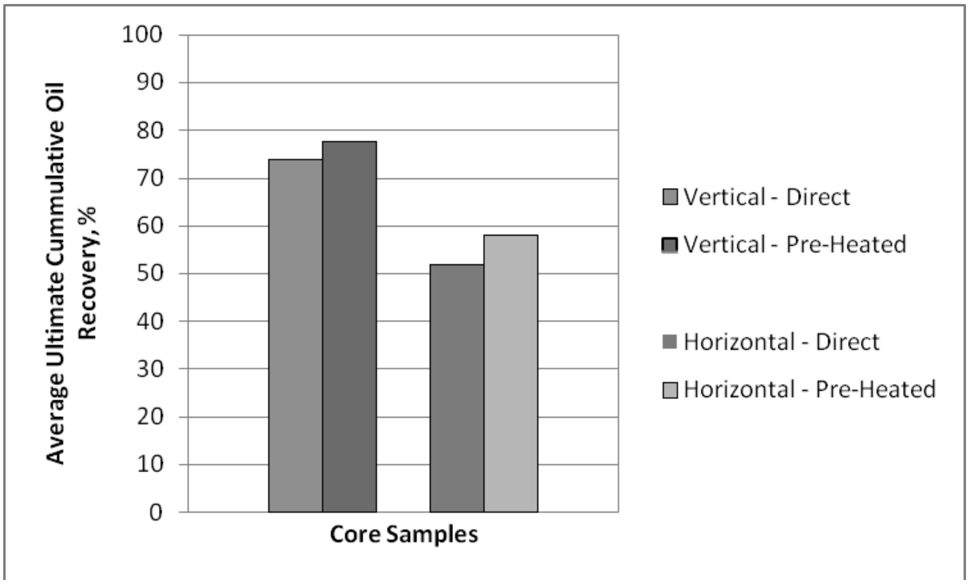

Fig. 9. Average ultimate cumulative oil recovery for all cores.

CONCLUSIONS

This study evaluates the efficiency of heavy oil recovery from Lower Fars reservoir using hot water flooding at various temperatures followed by steam flooding and direct steam flooding. The viscosity, density, molecular weight, and composition of heavy oil sample were estimated. Unconsolidated sandstone core samples from Lower Fars were used for hot water flooding at 60 and 80°C followed by steam flooding at 153°C, in both vertical and horizontal setting for cores 1 to 4. The effect of gravity was also investigated by placing the first two cores 1 and 2 vertically and cores 3 and 4 horizontally. The results showed that the average cumulative oil recovery from the vertical cores at 60°C, 80°C, and 153°C was 27.0%, 46.3%, and 77.5%, respectively. In addition, the average cumulative oil recovery for the horizontal cores at 60°C, 80°C, and 153°C was 26.1%, 43.1%, and 58.1%, respectively. Vertical displacement produced more oil than horizontal displacement; the former has a better displacement efficiency as it eliminates steam override. The oil recovery curves from the vertical displacement tests showed similar trends to each other. Also the curves for horizontal displacement tests showed similar trends to each other but differed from those of the vertical displacement. This indicates that small cores can be used for such test with high confidence.

The overall results showed that, for vertical setting, the average cumulative oil recovery when the cores are pre-heated (77.5%) was higher than direct steam flooding (74.0%). In addition, for horizontal setting, the average cumulative oil recovery when the cores are pre-heated (58.4%) was higher than direct steam flooding (52.0%).

ACKNOWLEDGMENT

The authors would like to appreciate the support received from Kuwait University for the use of Petroleum Fluid Research Center to measure fluid composition and viscosity. Also, they appreciate both Kuwait Oil Company for providing the cores and fluid samples and Kuwait Institute for Scientific Research for helping in the separation of the produced fluids. Finally, appreciation is extended to Rouqaya Karoon, Reem AlAbbas, Noor Hashem, and Dalal AlJasem, Petroleum Engineering students at Kuwait University, for their contribution in the direct steam flooding experiments.

REFERENCES

U.S. Energy Information Administration. 2016. Country Analysis Brief: Kuwait, November 2, 2016.

Clark , B., et al. 2007. The National Petroleum Council (NPC), 2007. Heavy oil 22.

Bursell, C. G. & Pittman, G. M. 1975. Performance of steam displacement in the Kern River field, Journal of Petroleum Technology, August 1975, 997-1004.

Chuansheng, S., et al. 1998. An experimental study of EOR by steam injection following water, 1998, No.142. Karma Oilfield, China, Petroleum Administration Bureau.

Willman , B. T., et al. 1961. Laboratory studies of oil recovery by steam injection, 1961, SPE. 1537-G, Petroleum Technology.

Hong, K. C. 1994. Steam quality and injection rate on steamflood performance, 1994, SPE.25788, SPE Reservoir Engineering.

Butler, R. M. 1985. A new approach to the modeling of steam assisted gravity drainage. The Journal of Canadian Petroleum Technology, March 1985, 42-51.

Bing-Bing Han, Wen-Long Cheng & Yong-Le Nian. 2017. Experimental study on effect of temperature field on recovery of reservoir using hot water flooding, Energy Procedia Volume 142, December 2017, Pages 3759-3765.

Barge, D., et al. 2009. Steam flood piloting the Wafra field Eocene reservoir in the partitioned neutral zone, between Saudi Arabia and Kuwait, 2009, SPE.120205-MS, Bahrain, Society of Petroleum Engineers.

Oskui, G. P., Al-Naqi, A. & Dusseault, M. B. 2009. Screening potential production technologies for lower fares heavy oil asset in Kuwait, 2009, SPE.126268-MS, Kuwait, Society of Petroleum Engineers.

Alwaqyan H. O., 2014, Experimental Investigation of Oil Recovery by Hot Water and Steam Flooding for Lower Fares Heavy Oil, M Sc. thesis, June 2014, Kuwait University.

Submitted: 09/07/2018
Revised: 23/10/2018
Accepted: 14/10/2018

تجارب مخبرية لقياس كميات النفط الثقيل المستخرج عن طريق حقن الماء الساخن و بخار الماء من مكمن فارس السفلي

يوسف سيد خلف سيد هاشم، حذامه عثمان الوقيان و عادل محمد الشرقاوي
قسم هندسة البترول، كلية الهندسة و البترول، جامعة الكويت

الخلاصة

في هذه الدراسة، أجريت تجارب مخبرية لحقن الماء الساخن وبخار الماء في ثمانية عينات حجريه رمليه غير متماسكه من مكمن فارس السفلى. أُجريت اختبارات حقن الماء الساخن عند 60 و 80 درجة مئوية وبعدها تم حقن البخار عند 153 درجة مئوية للعينات الحجرية الأربعة الأولى. كذلك تم اجراء اختبارات حقن البخار مباشرة عند 153 درجة مئوية للعينات الحجرية الأربعة الأخيرة. أُجريت اختبارات حقن الماء الساخن وبخار الماء بمساعدة الجاذبية الأرضية عن طريق الحقن الرأسي وكذلك عن طريق الحقن الأفقي. إن الهدف الرئيسي من هذه الدراسه هو مقارنة كميات النفط الثقيل المُستخرج من مكمن فارس السفلي عن طريق حقن الماء الساخن بدرجات مختلفة ومن ثم حقنه بالبخار مع حقن مباشر للبخار. سوف تُستخدم نتائج هذه التجارب لتحديد أفضل طريقة لإنتاج النفط الثقيل من مكمن فارس السفلى. وتشير النتائج إلى أن معدل نسبة النفط الثقيل المُستخرج من العينات عن طريق الحقن الرأسي بالماء الحار ومن ثم بالبخار هو 77.5% مقارنة بـ 74.0% للحقن المباشر بالبخار. بالإضافة إلى أن معدل نسبة النفط الثقيل المُستخرج من العينات عن طريق الحقن الأفقي بالماء الحار ومن ثم بالبخار هو 58.4% مقارنة بـ 52.0% للحقن المباشر بالبخار.