MECHANISMS OF EXTRA-HEAVY OIL RECOVERY BY GRAVITY-STABLE CO2 INJECTION

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ABSTRACT

Compared with thermal methods, non-thermal production of heavy oil can offer advantages on capital cost, energy consumption, environmental pollution, and safety. It also offers a solution for recovery from heavy oil reservoirs in which thermal methods are inefficient or not feasible. However, many advantages of heavy oil non-thermal production methods are usually contrasted by their low recovery factor. Pressure depletion, vapour extraction (Vapex) and water flooding are amongst the cold production recovery options but each has major drawbacks. Alternative non-thermal processes are therefore needed to increase oil recovery from heavy oil reservoirs. CO2 injection is increasingly considered as having potential applications as a possible IOR process. Displacement and recovery of conventional (light) oil with CO2 has been studied and applied extensively. However, much less experience has been gained on recovery of heavy and extra-heavy oil by CO2 and hence, this process is less understood.

In this paper we present the results of visualisation experiments carried out in a high-pressure transparent micromodel to investigate the performance of gravity-stable CO2 injection in an extra-heavy crude oil. We reveal the pore-scale interactions of CO2-oil-water and mechanisms of displacement and recovery through vivid micromodel images and videos. During extended periods of CO2 injection, the colour of the heavy crude oil was observed to change gradually but drastically from black to light brown as a result of the dilution of heavy oil with CO2. The discoloured diluted oil was readily mobilised and recovered during water injection carried out subsequent to CO2 injection and resulted in a very high oil recovery. The presence of water was observed to adversely affect the performance of CO2 injection. The results improve our understanding of the mechanisms of heavy oil recovery by CO2 and water injection and demonstrate a huge potential for CO2 injection as a heavy oil recovery method, which can provide energy, economic and environmental benefit.

INTRODUCTION

Worldwide there are huge quantities of heavy oil, extra-heavy oil, and bitumen resources. The International Energy Agency (IEA) estimates that there are 6 trillion barrels in place. This is twice as much as conventional oil resources. Hence, heavy oil has the potential to be a major energy source for the 21st century. Although currently the volume of heavy oil production is much smaller than the production from conventional (light) oil, the world's dependence on heavy oil production is on the rise mainly due to the projected massive increase in demand in near future. As the heavy oil market is expanding around the world, an increasing number of oil companies are either becoming involved or increasing their activities around heavy oil production.

Unlike conventional light oil, heavy oil is very viscous, semi-solid, or even solid. This makes the production of heavy oil much more difficult than conventional oil and hence, primary production from these reservoirs generally results in a very low recovery factor (typically only 5% to 10%). Water injection has been used to improve heavy oil recovery by enhancing formation pressure and to help displace the heavy crude but problems associated with low sweep efficiency and large water cut production are well documented (Jayasekera and Goodyear, 2000). The main cause of the poor sweep efficiency in heavy oil reservoirs is the unfavourable mobility ratio due to high oil viscosity. Various thermal methods and particularly steam injection (e.g., steam floods, cyclic steam stimulation, SAGD) have been developed and applied in the field to alleviate the problem of poor sweep efficiency in heavy oil reservoirs and to improve oil recovery by reducing the oil viscosity (Butler and Stephens, 1981, Josh and Threlkeld, 1985). Steam injection, however, cannot be efficiently and economically applied to many heavy oil reservoirs especially deeper reservoirs or those with a thin pay zone. Thermal methods are also very energy intensive with significant environmental impact. Alternative non-thermal recovery methods are therefore needed to increase oil recovery from these reservoirs. Compared to thermal methods, non-thermal methods offer advantages on capital cost, energy consumption, environmental pollution, safety and in-situ upgrading. They also provide a solution for recovery from heavy oil reservoirs in which thermal methods are impractical or uneconomical.

CO2 injection for improved recovery of conventional (light) oil has been studied and applied extensively. The main advantage of CO2 is that at most conventional reservoir conditions it is a supercritical fluid with high solvency power to extract hydrocarbon components and develop miscibility with oil. Furthermore, its high density makes it quite compatible with oil alleviating gravitational segregation. However, compared to light oil, application of CO2 injection in heavy oil reservoirs has received much less attention and to date very few heavy oil reservoirs have been produced by CO2 injection. There are two main reasons for this; first, in heavy oil reservoirs CO2 lacks acceptable sweep efficiency due to large viscosity contrast between CO2 and oil. Second, due to the presence of heavy hydrocarbon components in the oil, it is very unlikely that CO2 would develop a miscible front in heavy oil reservoirs. However, viscosity reduction in heavy oil, due to mixing with CO2, is much larger than in light oil and viscosity reduction of two orders of magnitude has been reported (Baviere, 1991, Klins, 1984).

The method can be used on its own or in conjunction with steam-based recovery methods where it has potential for reduction of CO2 emissions produced during steam generation operation and at the same time enhancing the oil recovery performance of the process through the injection of the separated CO2.

Mechanisms of interaction between immiscible CO_2 and heavy oil have not been fully investigated before and the interplay between diffusive and convective mechanisms during CO_2 injection is not fully understood. Significant improvements in the effectiveness of this method can be achieved by developing a better understanding of the complex mechanisms involved in CO_2 injection in heavy oil reservoirs. Direct visualisation (micromodel) experiments are a very useful tool to reveal these mechanisms and to investigate the impact of parameters pertinent to this method. The objective of the ongoing Heavy Oil Recovery JIP (joint industry project) at Heriot-Watt University is to investigate the application of CO_2/water injection for improving recovery from heavy oil reservoirs. Various injection strategies are being tested and different heavy crude oils are being used in an integrated experimental and theoretical approach. In this paper we focus on the observations made during immiscible CO_2 injection in an extra-heavy oil which was carried out as part of a comprehensive series of direct visualisation experiments that are being performed as part of this project.

EXPERIMENTAL FACILITIES

A high-pressure micromodel rig is being used to perform direct flow visualisation experiments. Details of the experimental facilities can be found elsewhere (Sohrabi *et al*, 2000, 2007, 2008).

Glass Micromodels

Micromodels are made of a two-dimensional pore structure, which is etched onto the surface of a glass plate, which is otherwise completely flat. A second glass plate is then placed over the first, covering the etched pattern and thus creating an enclosed pore space. This second plate, the cover plate, has an inlet hole and an outlet hole drilled at either end, allowing fluids to be displaced through the network of pores. Because the structure is only one pore deep, and the containing solid walls are all glass, it is possible to observe the fluids as they flow along the pore channels and interact with each other. It is also possible to observe how the geometry of the pore network affects the patterns of flow and trapping.
Various pore patterns can be designed and used in micromodel experiments. In this study a heterogeneous rock-look-like pattern was used. Table 1 includes the dimensions of the micromodel and its pores.

Fluids

A highly viscous crude reservoir oil, distilled water (without any added dyes or colouring agents), and CO_2 were used in the test. Table 2 presents properties of the same extra heavy crude oil sample that was used in the micromodel experiments.

In the micromodel pictures present in this paper, the fluids are shown in their real colour (oil is black and water colourless). However, to distinguish between gas (CO_2) and water, in the picture, CO_2 has been digitally coloured yellow.

Experimental Procedure

The performance of immiscible CO_2 injection was investigated after an initial waterflooding. The micromodel orientation in all stages of the experiment was vertical. The micromodel was first saturated with water and pressurised to 600 psig at 44 °C. To resemble the initial migration of oil in a water-bearing reservoir and to establish an initial oil and water saturation, the crude oil was then injected from the top of the micromodel and continued until the oil front reached the other end of the porous medium.

To simulated waterflooding of an oil reservoir, the model was then flooded with water for an extended period of time. After this initial period of waterflooding, gravity stable CO_2 injection was carried out from the top of the vertical micromodel. Then, the experiment continued with another cycle of water and CO_2 injection. The test was concluded by performing another water injection period, which was continued for a long period of time to strip the dissolved CO_2 out of the oil in order to obtain the residual oil saturation based on dead oil volume within the micromodel. All the fluid injection periods (water and CO_2) were carried out at a very slow rate of 0.01 cm^3/hr corresponding to a capillary number of 2.52E-7. The value of capillary number indicates a capillary dominated flow regime, which was also confirmed by visual observations made during the experiments.

The change in heavy oil properties and CO_2 diffusion coefficient in oil, which depends on oil viscosity, with time due to CO_2 diffusion were not measured in this experiment. Work is currently underway to quantify these changes, which will be complemented by the pore scale modelling of the process, in near future.

RESULTS AND DISCUSSIONS

Oil Flood

Having saturated the micromodel with water at the pressure and temperature of the test, the heavy crude oil was injected to establish the initial oil and connate water saturation. Since the viscosity of the oil was significantly higher than the resident water, the displacement process was very efficient with the crude oil displacing almost all the water present in the micromodel and leaving behind very low water saturation. Saturation of water in the micromodel after this oil flood was estimated to be less than 5% with water remaining mostly in the dead-end pores and in pores in which the geometry of the pore would not allow the displacement of the water. Figure 1 shows the distribution of oil and connate water in a section of the micromodel at the end of the oil flood period.

To show the images of the micromodel at a suitable magnification, only the image of a middle section of the micromodel, which is representative of the whole micromodel, is presented in Figure 1 and throughout this paper.

Wettability of the System

During the oil flooding stage the system remained water wet, as evidenced by positions of the fluids within the pores and shapes of fluid contacts and interfaces. This observation contrasts with expectations for an oil that contained asphaltenes and resins. Surface-active compounds in crude oils, e.g., asphaltenes and resins, which are partially soluble in water, have been reported to alter the wettability from water-wet to oil-wet and hence, it is generally assumed that parts of the porous medium in contact with crude oil exhibit oil wet characteristics (Tiab and Donaldson, 2004). Since the crude oil used in this test had a high asphaltene content (11.6 wt %) we expected to observe a very oil-wet medium after crude oil injection. However, at the end of the oil flood period the micromodel was still water-wet with no indication of wettability alteration towards oil-wet. This highlights one of the important advantages of micromodel experiments, as opposed to coreflood tests, where the wettability of the porous medium could be directly visualised rather than being assumed or inferred from indirect measurements or indices. In micromodels, the shape of the fluid-fluid interfaces and distribution of water and oil in the pores are clear indications of the state of wettability of the porous medium.

Water Flood

Having carried out the oil injection described above, water was injected into the micromodel for an extended period of three days to simulate the process of waterflood for this crude oil.

With the porous medium retaining its water-wet characteristics, the injected water was observed to flow mostly in the form of layers on the walls of the pores rather than distinct piston-type displacement mechanisms. Water films surrounding the oil were seen to thicken progressively leaving oil in the middle of the pore bodies and finally causing oil snap off in pore throats. Similar mechanisms for waterflooding in water-wet porous media have been observed in our laboratory and reported in our previous publications (Sohrabi et al, 2000, 2007, 2008). Since in the rock-look-alike micromodel used in this study, the connectivity of the left hand side of the micromodel is considerably higher than the right hand side, the injected water flowed originally in the left side of the micromodel and later developed into the right side as well. Figure 2 illustrates the same section of the micromodel at the end of the water injection period, 3 days of water injection. As it can be seen, by comparison of Figure 1 with Figure 2, water has displaced and recovered a very limited amount of the oil. Only a small fraction of the original oil in place was recovered at the end of the water flood period.

Change of Fluid Distribution during Water Flood

Based on our extensive micromodel experience, during waterflooding, the pattern and distribution of water and oil within the micromodel remains essentially unchanged shortly after water breakthrough. However, the behaviour of the extra-heavy crude oil used here was totally different during water flooding period. As the water injection continued, oil recovery and the change in water and oil distribution continued too and the flowing water affected a progressively larger area of the micromodel. Figure 3 shows the same selected section of the micromodel during water flooding of this crude oil after few hours of water injection. As it can be seen from comparison of this Figure with Figure 2 which shows the same section at the end of water injection period the originally narrow path of water continued to grow laterally from the left to the right side of the micromodel.

Tertiary CO2 Flood

After this water injection period, to simulate gravity stable tertiary injection of CO_2, the first period of CO_2 injection commenced. CO_2 was injected from top of the micromodel.

Being a non-wetting phase, the injected CO_2 was observed to flow in the middle of the pores as opposed to water (wetting phase), which flowed in layers on the walls of the micromodel pores, in the preceding water injection period. The interfacial tension between the fluids were not measured but during the invasion of the porous medium by CO_2, as the CO_2 front advanced towards the producing end of the micromodel, crude oil was observed to spread between CO_2 and water phases despite the fact that the viscosity of the oil was 4 orders of magnitude higher than water phase at the test conditions. In the areas with relatively high oil saturation, a small bank of oil formed and flowed ahead of the CO_2 front and hence, the advance of the CO_2 front was associated with the movement of oil-water interfaces ahead of it (double displacement). In the micromodel areas with low oil saturation, a layer of oil covered the CO_2 front, which was indicative of a spreading system (Oren, 1994, Sohrabi 2000).

Figure 4 presents the same selected section of the micromodel after two days of CO_2 injection, which shows rather poor sweep efficiency. There are two main reasons for this poor sweep efficiency during CO_2 injection; first the viscosity contrast between CO_2 and water and the crude oil result in a very unfavourable mobility ratio and hence, CO_2 fingering through the porous medium toward the production end of the micromodel; and second, the presence of high water saturation which has disconnected the oil and has further reduced its mobility.

The injection of CO_2 through the micromodel resulted in significant dilution of the crude oil as the injection of CO_2 continued. Figure 5 shows two images of the same section of the micromodel during CO_2 injection after breakthrough of CO_2 (5a) and at the end of the two days CO_2 injection period (5b). As it can be seen, the colour of the areas of the crude oil, which are in direct contact with CO_2, has changed from black to a brown, which is an indication of the dissolution of CO_2 in the crude oil and the subsequent dilution of the crude oil to a lighter mixture of the oil and CO_2. It is to note that the light intensity was uniform during these equipments and the colour change could only be due to dilution of oil as a result of CO_2 injection. Figure 5 also demonstrates the presence of a layer of water between the oil in the left hand side of the micromodel, which separates the flowing CO_2 from the oil resident in the right hand side of the micromodel. As it can be seen, although there is slight discolouring of oil on the right side of the micromodel, however, it is not comparable with the extent of colour change in the left hand side of the micromodel, which is in direct contact with CO_2. This implies that secondary (pre waterflooding) injection of

CO2 in which the oil phase is mainly connected and continuous would result in a more efficient process and hence, higher oil recovery.

2nd Period of Water Injection

The first extended CO_2 injection period, which was carried out for two days, was followed with the second period of water injection, which continued for two hours. Figure 6 shows the same section of the micromodel at the end of the second water injection period. Flow of water caused the continuous path of the CO2 in the micromodel to become discontinuous and fragmented. Water also was observed to dissolve the CO2 and eventually all of the CO2 contained in the micromodel was dissolved in the flood water at the end of the water injection period.

Comparing oil saturation in the selected section of the micromodel at the end of the first period of CO2 injection (Figure 4) and after the subsequent water injection period (Figure 6) shows that significant additional oil recovery has taken place during the second period of water injection. As the oil was readily mobilised and produced during the second water injection period, it was inferred that the dissolution of CO2 in the oil, during the preceding CO2 injection, significantly reduced the viscosity of the oil. Comparing the oil saturation in the selected section of the micromodel after the first water injection period (Figure 2) and second water injection period (Figure 6) illustrates that the second water injection period has significantly improved oil recovery, which would have not been possible without a significant viscosity reduction of the oil during the preceding CO2 injection.

During the second period of water injection the crude oil gradually lost some of its brightness, which had gained during the first period of CO2 injection and became darker. The loss of the brightness of the crude oil can be explained by the stripping effect of the flowing water on the oil, which tends to strip some of the CO2 that had been dissolved in the oil in the preceding CO2 injection. However, at the end of the second water injection period, the colour of the crude oil was not completely restored to its original black colour. The remaining crude oil was not as bright as after the first CO2 injection period (Figure 5) nor as dark as the colour at the beginning of the test either (Figure 1).

2nd Period of CO2 Injection

After the second water injection period, which was carried out for a relatively short period of time (two hours), a second period of CO2 injection was started and continued for 24 hours. Figure 7b shows the same section of the micromodel at the end of the second CO2 injection period.

This second CO2 injection period resulted in very little improvement in oil recovery as the CO2 mainly flowed through the left hand side of the micromodel, which had already been flooded with water and CO2. As mentioned before, the left hand side of this micromodel has a much better connectivity compared to the right hand side of the model. Similarly to the first CO2 injection period, the oil was observed to have a tendency to spread between the CO_2 and water phases. As the saturation of oil in the micromodel was less than the first CO_2 injection period, this tendency resulted in formation of oil layers on the CO_2 stream rather than formation of a bank of oil in front of the CO_2 advancing front.

An important observation during this period of CO_2 injection was the change of the colour of the crude oil but in the opposite direction of what had been observed in the 1st cycle of CO_2 injection. In the first period of CO_2 injection, due to the dissolution of CO_2 in the oil, the colour of the oil became lighter and in the subsequent water injection period the oil colour changed back slightly and became darker due to the partial loss of the dissolved CO_2. It was expected that in the 2nd period of CO_2 injection the colour of the remaining oil would again become light. But the colour of the remaining fragments of the oil, which were in direct contact with the flowing CO_2, did not get any lighter and on the contrary they even became darker. At the same time, the colour of the part of the remaining oil which was not in direct contact with the flowing CO_2 (separated with water) either retained its colour or became slightly lighter.

Figure 7 compares the same section of the micromodel after breakthrough of the second period of CO_2 injection (Figure 7a) and at the end of this period (Figure 7b). The area specified by the blue circles show the areas in which the oil became darker and the one specified by the red circle shows the area, which was not in direct contact with CO_2 and preserved its colour or became slightly lighter. It can also be noticed from Figure 7 that the darkening of the crude oil (blue circled areas) is also associated with shrinkage of the oil, which indicates the evaporation of the oil into the CO_2 stream. Comparison of the selected section of the micromodel after the first and second CO_2 flooding periods (Figures 4 and 7b, respectively) clearly shows the contrast between the crude oil colour as a result of the reverse mechanisms in the first and second period of CO_2 injection.

3rd Period of Water Injection

At the end of the experiment the micromodel was once again flooded with water in order to be able to determine the dead-oil residual saturation and the shrinkage factor of the oil by stripping the dissolved CO_2 out of the crude oil. Figure 8 shows a section of the micromodel at the end of the test. Comparing the oil saturation in the selected section of the micromodel after the third period of water injection (Figure 7) and second period of water injection (Figure 6) shows that there has been a slight recovery of the oil during the third water injection. This additional oil recovery was minimal and almost all of the oil recovery took place during the previous cycle.

CONCLUSIONS

1. Waterflood of the extra heavy oil initially resulted in a poor sweep efficiency and recovery. This was mainly due to a very unfavourable mobility ratio due a large viscosity contrast between the crude oil and water. However, as the injection of water continued, a larger part of the porous medium was affected with the floodwater and more oil was recovered.

2. Extended tertiary CO2 injection brought about significant dilution of the oil as a result of mixing with CO2 and resulted in significant additional oil recovery during the water flooding period carried out subsequent to CO2 injection.
3. In the first period of CO2 injection, dissolution of CO2 in the oil was observed as evidenced by oil swelling. In the second period of CO2 injection, however, oil vaporisation was observed which was associated with shrinkage of the oil.
4. The major portion of additional oil recovery was obtained after first cycle of CO2/water injection. A small amount of oil was produced during the second cycle of CO2/water injection as a result of high sweep efficiency in the first cycle.
5. No evidence of major asphaltene precipitation or deposition was observed despite high asphaltene content of the heavy oil.
6. CO2 was observed to displace oil by a double drainage mechanism during CO2 front advance in the micromodel despite the fact that viscosity of oil was significantly higher than water.

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Table 1: Dimensions of the micromodel and its pores.

Height cm	Width cm	Pv Cm^3	Ave. depth μm	Pore Dia. Range μm
4	0.7	0.01	50	30-500

Table 2: Basic properties of the extra-heavy crude oil used for the experiments.

API	Viscosity (cp)	Asphaltene Content (wt/wt%)	Acid Number (mgKOH/gr)
11.5	5500 @ 60 °C	11.6	3.38

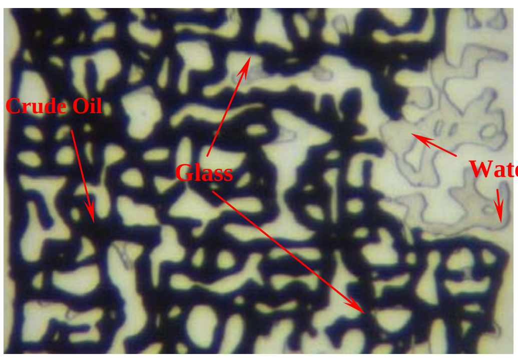

Figure 1: Fluid distribution in a section of micromodel after oil flood.

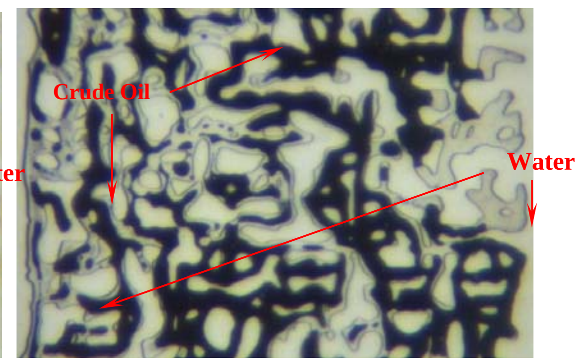

Figure 2: Fluid distribution in the selected section of the micromodel at the end of the water flooding period.

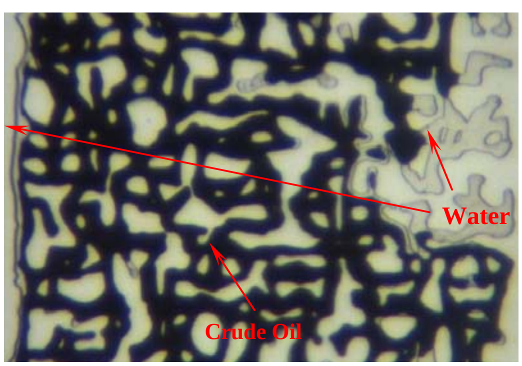

Figure 3: Oil recovery and fluid distribution in the selected section of the micromodel after few hours of water flood.

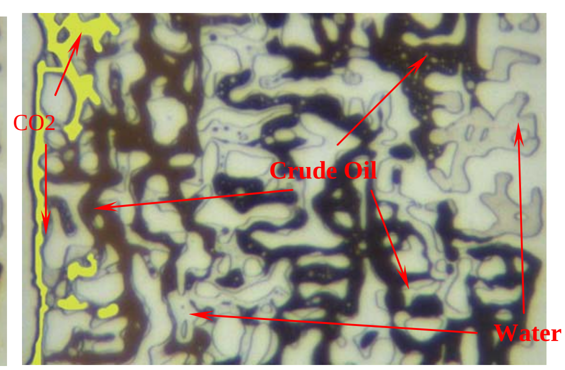

Figure 4: Fluid distribution in the selected section of micromodel at the end of the first period of CO2 injection.

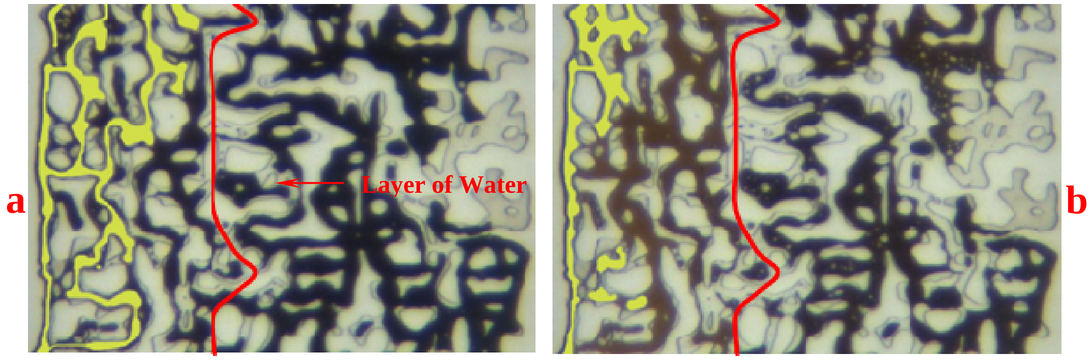

Figure 5: Crude oil dilution in the selected section of the micromodel during the first period of CO_2 injection after a) a few hours, and b) 2 days of CO_2 injection.

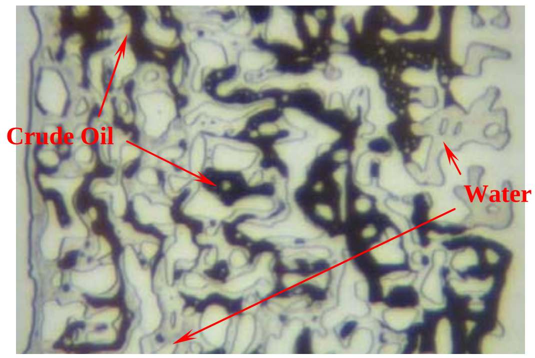

Figure 6: Fluid distribution in the selected section of micromodel at the end of the second period of water injection.

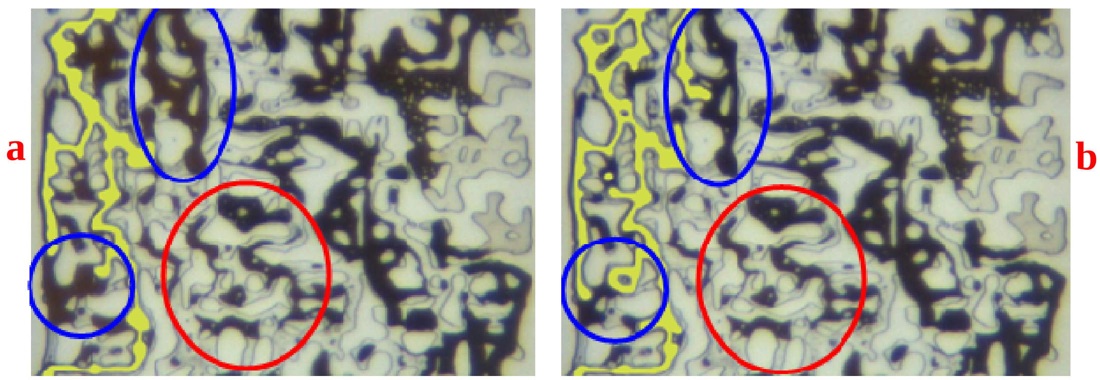

Figure 7: Crude oil colour change in the second period of CO_2 injection after a) breakthrough of CO_2 and, b) 24 hours of CO_2 injection. The areas which have been specified with the blue circles were in direct contact with CO_2 and became darker after the second period of CO_2 injection and the area in the red circle is example of the part of the oil which was not in direct contact with CO_2 and has retained its lighter colour.

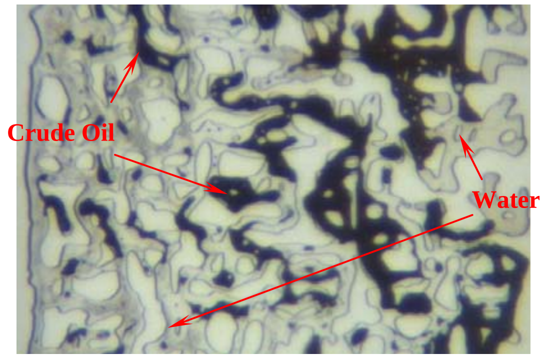

Figure 8: Fluid distribution in the same section of micromodel at the end of the third period of water injection.