VERTICAL WATER INJECTION IN A HETEREOGENEOUS SAND COLUMN; EXPERIMENT AND ANALYSIS

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Introduction

Partly gravity dominated water floods take place in several North Sea oil fields. A characteristic feature of some of these water floods is a significant reduction of the oil saturation behind the water front versus time. Field data that support this statement is data from observation wells where saturation logs are run on approximately a yearly basis [1]. This reduction of the oil saturation behind the water front is explained phenomenological by interpreting the rock as being mixed wet for the oil- water- rock system involving oil flow through films [2] .

There is a fundamental question to this recovery/displacement process concerning the relative permeability characteristics, residual oil saturation and how representative data from standard SCAL experiments are. For strongly wetting systems it is possible to scale the viscous and gravity forces for prediction of residual oil saturation [3]. However, for mixed wet systems it is difficult to perform properly scaled SCAL experiments reproducing the characteristics of a gravity dominated displacement over a vertical distance of several tens of meters or more. The main difficulty is maintaining the wetting properties while reducing the capillary forces in a small scale model. A closer inspection of the relevant scaling groups governing the dynamic process on the pore scale and on the macroscopic scale, shows that a properly scaled experiment to model the gravity dominated water flood process requires a long vertical flow rig, which is flooded at a relatively low rate to ensure a gravity stable water flood. The length requirement depends on the capillary forces and the vertical extent of the capillary transition zone. One of the main phenomena, which is difficult to scale, is the flow of oil through continuous films over long distances driven by gravity and capillary forces. In this study the wetting behaviour was prepared by using fresh core, reservoir fluid and aged material.

Purpose of study

The main purpose of this study is to test the concept of using a long vertical flow rig to study oil recovery by gravity stable water flood for a mixed wet system.

Construction of a long vertical flow rig with real reservoir core material is difficult since only bore hole cores are available. The actual concept is to construct a long vertical flow rig consisting mainly of specially prepared sand plus a small number of reservoir cores (length 5 - 10 cm) placed alternately with sand as shown in Fig. 1. For typical core material properties a flow rig of length 15 - 20 metres is necessary to achieve strong enough gravity forces. However, there are a number of critical experimental conditions that needs to be assessed in order to be sure that it is possible to get the correct dynamic behaviour during the flood. The three most critical conditions are: i) capillary continuity between the sand and the reservoir core samples, ii) capillary continuity within the sand pack itself and iii) the mixed wetting property of the sand pack. A smaller scale test project was set up to establish a flow rig construction procedure and to test whether the selected solutions/procedures satisfy the requirements for a successful full scale experiment.

Experimental setup and results

In situ saturation measurements were performed using gamma ray monitoring during the experimental period of 68 days. This was done by doping the synthetic formation water (SFW) with CsCl. After initial water saturation was established for sand and cores, aging in crude oil for three weeks at 70 °C and 5 bar was done.

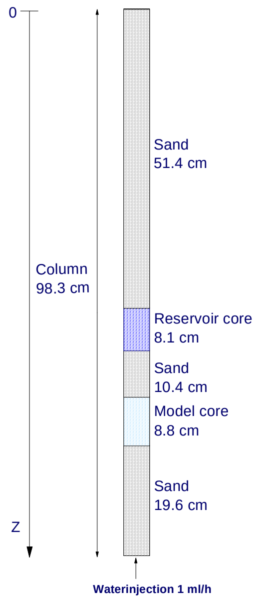

Figure 1. Sketch of the column.

A quartz rich sand, orginally water wet, was prepared by drying and sieving. After adding SFW to obtain 10 % water saturation, crude oil in excess was mixed in. Two Bentheimer model cores were saturated with SFW. Oil drainage to establish initial water saturation was done by porous plate technique at 70 °C and 5 bar. A reservoir plug was cleaned by flooding with SFW. Initial water saturation was established by crude oil flooding.

The column was assembled as shown in Fig. 1. Packing of the column started from bottom, where a fine mesh was installed in order to prevent loss of sand grains. Core plugs were cast into the column with epoxy. The sand, grain size from 0.07 to 1.0 mm, was packed in small portions with excess of oil and it was compressed by use of a special piston where excess oil and air could pass through. Table 1 shows the petrophysical properties of our reservoir. Assuming 10 % residual water saturation STOOIP is 498 cm^3. After installation of the column it was mounted in the gamma attenuation rig. In situ saturations were measured every 20 mm in the sand sections and every 5 mm in the core plugs. Each day 2 series of saturation profiles was measured, one turn took about 6 hours.

Oil injection at 5 bar line pressure was carried out until gamma ray signal along the core was stabilized. SWF was injected into the bottom of the column at a flow rate of 1 ml/h for 47 days. After a shut-in period for 13 days, the injection was resumed for 8 more days. Water injection was carried out at 21-22 °C and 1 bar line pressure. During the flooding sequence oil production and differential pressure was continuously recorded.

Table 1. Petrophysical properties.

Section	Poro (frac)	K (mD)
Sand	0.42	500
Reservoir core	0.382	1 132
Sand	0.42	500
Model core	0.234	2 510
Sand	0.42	500

Fig. 2 shows the oil production from the column versus time. Breakthrough of water (BT) occurred after 15.4 days or 369 ml oil produced. The shut-in period started when production of oil was 390 ml. Total oil production was 398 ml, indicating 80 % recovery of STOOIP. A selection of measured saturation profiles along the sand column is shown in Fig. 3. Those were strongly influenced by heterogeneities in the column i.e. contrasts in porosity and permeability, see Table 1, and also by wettability heterogeneities. The measured saturation profiles at the end of the water flood showed low water saturation in both cores. In the sand, however, experimental results indicate much higher Sw-values behind the water front, and the water saturation increased somewhat with time after the water front had passed. A significant gradient in water saturation (Sw) along the cores was observed. The water phase advanced with a sharp front indicating a gravity stable displacement, even though the viscosity ratio was 4. The reproducibility of the gamma ray measurements was convincing, meaning that the tendency of the observations was correct.

Numerical simulations of the water injection experiment required flow properties for the sand and the cores in the column. Multispeed centrifuge experiments were performed on samples of the sand and on a model core similar the one packed in the column. The reservoir core relative permeability and capillary pressure data were taken from a previous study. Results on Amott Wettability index are shown in Table 2. Altering the wettability properties of the originally water wet sand by aging failed. As a result of this, it was not possible to estimate imbibition relative permeability or capillary pressure data for the sand. Flow properties for the mixed wet Bentheimer core were obtained from interpretation of the multispeed centrifuge experiment using a special core flood simulator [4].

Table 2. Wettability properties.

Sample	Amott index
Sand	0.9
Bentheimer	0
Reservoir	-0.1

Numerical simulations

A one-dimensional, 2-phase numerical simulation model with 989 grid blocks in z-direction was used. The production well was controlled by bottom hole pressure and the injection well by injection rate. The reservoir was divided into 3 regions in order to account for different rock properties. Petrophysical data was taken from Table 1. Numerical simulations were done to analyze and history match some of the available data after the experiment: Oil production, differential pressure, saturation profiles and final saturations in the column. The objective of the simulation study was to reproduce the main observations from the experiment by adjusting relative permeability and capillary pressure. The history matching focused on: Breakthrough time, oil production after BT, movement of water front and the saturation profile development in the cores.

In the simulation study, different assumptions on capillary continuity between sand and core plugs were tested. Further, the wetting properties of the sand were varied from strongly water wet, the original assumption, to slightly mixed wet. Water saturation profiles from the final simulation are presented in Fig. 4 together with experimental data. The most important results from these sensitivity tests were:

1. The capillary continuity was broken between the sand and the core plugs. This assumption was supported by a) low water saturation in the core plugs after the waterfront had passed and b) no increase in water saturation in the core plugs during the shut-in period.
2. The water saturation profile in the two cores after the water front had passed, reflected the shape of the negative part of the imbibition capillary pressure curve. The saturation

profile along the reservoir core was reproduced using the original input data. The capillary pressure curve of the Bentheimer core was adjusted somewhat to obtain a reasonable match with observations.

3. The oil production after BT was distinct, although relatively small. This oil was mainly produced from the sand filled parts of the column, which showed water- to mixed wet characteristics. The recovery rate from the sand became oil relative permeability limited at high water saturations, an effect that was not in conflict with the assumption of lacking capillary continuity. The in-situ water saturation measurements supported this assumption, showing a small increase in Sw in the sand behind the water front.

4. A region near the top of the column showed untypical behavior compared to the rest of the sand in the column, which will influence on all results. The reason for this is not clear, however, poor quality of the sand packing is likely with poor capillary continuity as one possible consequence.

5. The simulation model was not able to reproduce the oil production volume after the shut-in period. This indicated that the measured data for the sand, was not capable of modelling the tail production during a gravity stable water flood.

6. BT was reproduced by increasing the porosity in the sand regions from 42 %, calculated from gamma ray measurements, to 49 %. This value is in accordance with the SCAL tests.

Analytical saturation profiles

From the *in-situ* measurements, the observed saturation changes in the domain where the front had passed appeared to be small, including the 2 core plugs. That means that the saturation distribution in the whole column after breakthrough was close to a steady-state “residual oil”, which could be obtained from a steady-state model taking into account viscous, capillary and gravity forces. Since a classical paper [5], such a model has been utilized in a number of papers to analyze capillary effects in a heterogeneous cores. For 2-phase flow, steady-state saturation distribution in 1D is governed by the equation

$$\frac{L\mu_w u_t}{k}\left[\frac{F}{k_{rw}} - M\frac{(1-F)}{k_{ro}} - N_{gv}\right] = \frac{dP_c}{dZ}, \qquad M = \frac{\mu_o}{\mu_w}, \quad N_{gv} = \frac{k\Delta\gamma}{\mu_w u_t},$$
$$\Delta\gamma = \gamma_w - \gamma_o,\ Z = z/L, \quad P_c = p_o - p_w, \quad \gamma_i = \rho_i g,\ i = w,o \qquad (1)$$

To qualitatively describe the residual saturation distribution in the heterogeneous column at hand, the flow functions in Eqn. (1) with analytical expressions enables simple analytical treatment. These expressions were:

$$k_{rw} = C_w S_n^{Ew}, \quad k_{ro} = C_o(1-S_n)^{Eo}, \quad P_c = A - \frac{B}{(1-S_n)^{Ep}}, \quad S_n = \frac{S_w}{1-S_{or}} \qquad (2)$$

A,*B:* Capillary pressure model parameters *C*: Relative permeability model parameter
E_i: Corey type exponent for relative permeability (i = o, w) E_p: Corey type exponent for capillary pressure *F*: Water phase fractional flow *L*: Model vertical length P_c: Capillary

pressure *S:* Phase Saturation *g*: Gravity acceleration *k*: Permeability k_r: Relative permeability p: Pressure u_t: Total liquid Darcy velocity *z*: Vertical position μ: Viscosity

From Eqn. (2) the normalized saturation was derived as a function of the capillary pressure, which in turn expressed the relative permeabilities as functions of the capillary pressure as well thereby facilitating the solution of the Eqn. (1). The relevant boundary condition for the considered case was specified at the outlet end as $P_c(z=0)=0$.

The capillary pressure curves used in this solution was somewhat different from the data used for numerical solution. This analytical model assumes capillary continuity through the whole column. The resulting saturation profile versus depth, shown in Fig. 5, reproduces qualitatively some of the main characteristics of the experimental observations. However, the saturation profile in the two cores are poorly matched, since the capillary pressure in the cores are significantly higher in this approach than what was observed in the experiment.

Conclusions

1. The necessary conditions for a successful long vertical flow rig experiment were not satisfied because the experimental results strongly indicate that the capillary continuity was lost between the cores and sand column.
2. The oil production after BT was mainly from the sand, thus showing water- to mixed wet properties of the sand.
3. The total oil production from the sand is consistent within the SCAL measurements for the sand.
4. The numerical simulations were important in order to obtain a good understanding and interpretation of the experiment.
5. The results from the analytical steady-state solution revealed only qualitatively the main characteristics of the measured saturation profile in the heterogeneous sand column.

References

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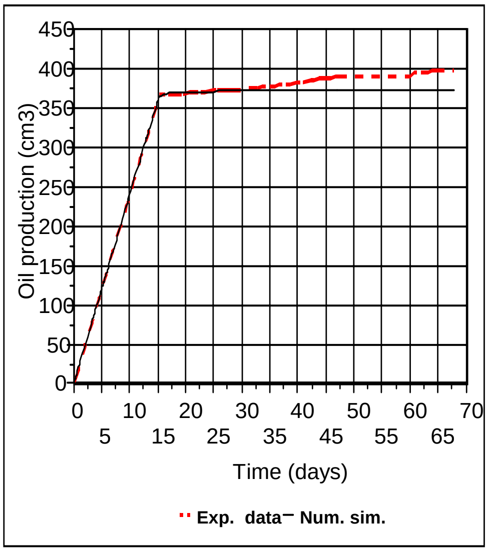

Figure 2. Oil production from the column.

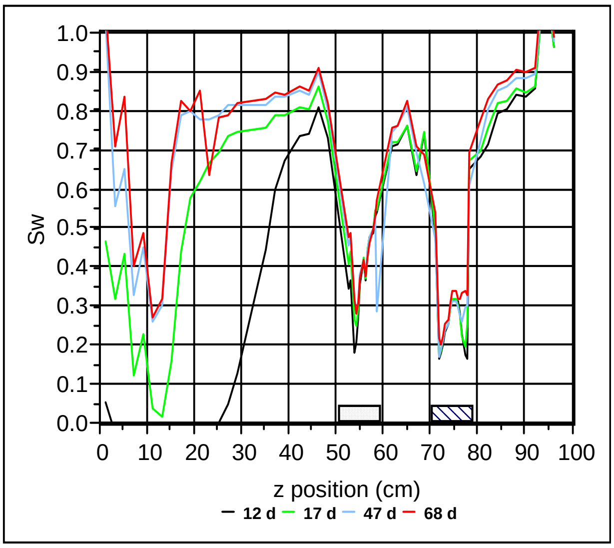

Figure 3. Water saturation profiles from gamma ray attenuation (d=days). Position of cores are indicated.

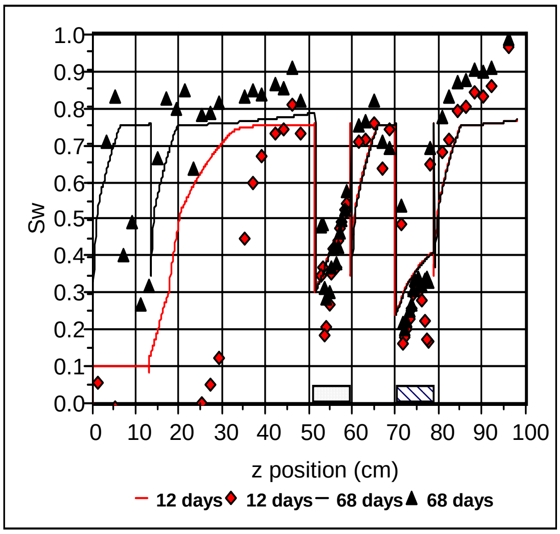

Figure 4. Water saturation profiles, lines from simulation and markers from experimental data.

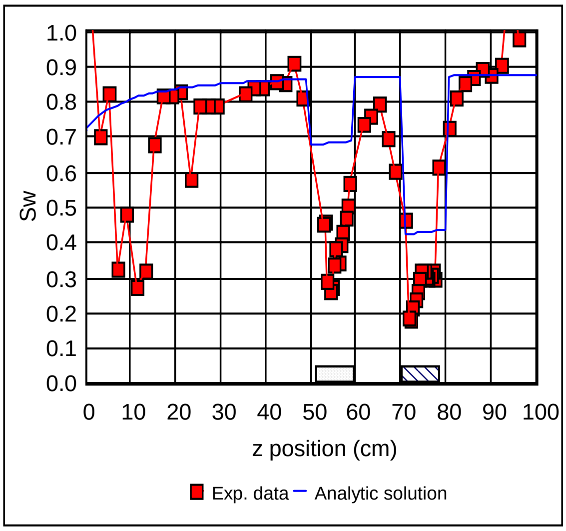

Figure. 5. Water saturation profiles from analytical model compared with in-situ measurements.