Two Dimensional Imaging of Fluid Flow in a large Slab of Heterogeneous, Cross Bedded Sandstone

Graue A., Pedersen E.
Univ. of Bergen, Norway

Abstract

In-situ fluid saturation imaging in two phase flow experiments in heterogeneous laminated sandstone are reported. Core floods and fluid displacement in a 2-dimensional physical reservoir laboratory model have been studied. The studies emphasize effects from capillary heterogeneities, permeability variations and the impacts different angles of lamination may have on local fluid saturation development, distribution of residual oil and local recovery efficiency in cross-bedded environments. The objectives have been to describe, understand and predict local saturation development during waterfloods in cross-bedded sandstone under various flow conditions.

Experiments evaluating the impacts of various dip angles relative to the advancing water front in a cross-bedded sandstone, have been conducted using cores drilled at $30^\circ$, $45^\circ$ and $90^\circ$ angles with respect to the bedding plane. Permeability variations of two orders of magnitude were recorded, but no significant impact on the oil recovery was observed.

A difference in recovery in the various layers was observed for the laminated sandstone, as each layer has unique capillary characteristics. However, probably due to thin lamination in the natural heterogeneous rock, significant effects of the interaction between the capillary forces and the small scale heterogeneities were not observed.

This work shows that obtaining two dimensional local fluid saturation information in large slabs of natural rocks improves the interpretation of the recovery mechanisms in heterogeneous media.

Introduction

Experimental studies of flow behaviour representative for a given reservoir formation are limited to minute fractions of the reservoir, i.e. samples taken from wellbore cores. The rock characteristics, however, usually vary spatially quite considerably.

Concern about this spatial variation of rock properties has recently lead to a growing interest to understand how different types of heterogeneities influence the displacement processes. This interest is partly due to the fact that modern technology now offers possibilities through improved computational means, to model and calculate large-scale effects from reservoir heterogeneities.

Better fundamental understanding derived from laboratory experiments, of how heterogeneities influence fluid flow may contribute to improvement of numerical models. Incorporating these effects in large-scale simulations will improve the reservoir management for enhanced recovery. Thus the objective of this work is to contribute to the goal to describe, understand and predict local fluid
saturation development during waterfloods in cross-bedded sandstone under various flow conditions.

Oil trapping due to interactions between capillary forces and small scale heterogeneities is generally not considered in reservoir engineering decisions, but may play an important role in determining ultimate oil recovery. The reported work considers oil trapping in small scale heterogeneities in the form of cross-beddings and laminations. These heterogeneities are generally observed at various scales in most clastic sediments. This trapping mechanism has recently been discussed in the literature, ref. 1.

Our interest and experience on flow in cross-bedded sandstone emerged from experiments initiated by some unexpected results concerning saturation development in long-core flood displacements in what was believed to be homogeneous eolian sandstone. The results from this study underscored the importance of knowing the local saturation development during oil production from heterogeneous media, ref. 2. The effects on the recovery efficiency were found to be due to permeability variations and capillary heterogeneities. Similar physical and geological experimental conditions as in the eolian sandstone were therefore re-established under controlled and systematic experimental investigation, by careful packing of sandcolumns, ref. 3. The objective was to reproduce some of the results from the eolian sandstone and systematically study impacts from parameter variations.

The present work continued our flood experiments with flow through cross layers with different permeability and capillarity, but with almost the same porosity. This paper includes a study of the impacts on the fluid flow from different dip angles of the cross-bedding relative to the flow direction. We also report on 2-dimensional (2D) imaging of fluid flow in a slab of laminated sandstone. The experiments have been performed in a recently constructed flow-rig utilizing dynamic 2D in-situ fluid saturation imaging of 2D physical reservoir models. Experiments in laboratory 2D-models exhibit the advantage of having an optimal geological and petrophysical characterization of the "reservoir". In cross-bedded models each layer is characterized with regard to porosity, permeability and capillarity. Minipermeameter measurements on the model further enhances the characterization. In-situ measurements of fluid saturation distribution by a tracer technique, ref. 4, 5, give information on the recovery mechanisms.

Work Performed

The cross-bedded sandstone material has been collected from the Mesaverde Group near the Wasatch Mountains, south-east of Salt Lake City in Utah. The outcrops were well exposed and easily accessible, often from three sides. This area exhibits various types of depositions; cross-bedded sandstones from fluvial, shallow marine and deltaic deposits were collected. Interdisciplinary collaboration in outcrop field work by reservoir engineers and geologists was very successful.

A portable road surface cutter was used to obtain slabs of rock from selected exposures. Sufficient material for several core flood experiments and 2D-rig experiments were obtained.

The cross-bedded sandstone used in this work was selected from fluvial and shallow marine deposits. Core material for evaluation of the nuclear tracer imaging system for this heterogeneous rock had earlier been obtained by geologists working in the Price River area. Plugs of 1.5" in diameter were drilled from this material and used in core flood experiments. Standard core data such as porosity, absolute permeability and capillary pressure data were obtained. The capillary pressure data were obtained by the use of a centrifuge. In addition capillary pressure curves and pore size distributions by mercury injection were obtained. Each of the plugs, obtained from various units in the Castlegate and Blackhawk Formation in Price River Canyon, was used in three successive displacements; a miscible brine/brine displacement, a drainage and a waterflood. The nuclear tracer imaging technique was used throughout the core floods.
The evaluation of the nuclear tracer imaging technique for experiments using the heterogeneous sandstone material was conducted to check the validity of the saturation information, especially with regard to absorption of tracers on the rock surface. Absorption is one potential disadvantage using the low cost nuclear tracer imaging technique on heterogeneous material. Information on one dimensional fluid saturation distributions was obtained by labelling the brine phase by a nuclear tracer, $^{22}\text{Na}$ in the form of sodium chloride, and detecting the radiation by a moveable detector. The results from this study concluded that although some absorption was observed, the local saturation information was reliable for the purpose of studying immiscible displacements in the selected cross-bedded rock.

In miscible displacements, where radioactive brine displaced inactive brine and vice versa, dispersion and ion adsorption were evaluated. Comparisons between effluent profiles and in-situ saturation data were used to verify true local saturation information.

Imaging the saturation profiles during immiscible displacements gave information on saturation, front velocity, time development of local saturation variations, recovery efficiency and distribution of initial- and final water saturations.

Various core flood displacements in consolidated sandstone cores were conducted, including both drainage and waterflood. The benefits from knowing the local in-situ saturations, the identification of rock heterogeneities and the experimental repeatability were stressed.

Experiments evaluating the effect of different dip angles relative to the advancing water front in cross-bedded sandstone were conducted in core flood experiments using cores drilled at $30^\circ$, $45^\circ$ and $90^\circ$ angles with respect to the bedding plane, see Figure 1.

The same slab of cross-bedded sandstone used to obtain the core plugs was cut to a 2.5 cm thick irregular slab of rock, ca 15x30 cm, see Figure 2.

Geological and petrophysical characterizations were performed on the slab of rock, including minipermeameter measurements; the permeameter map is shown in Figure 3.

Figure 1. Core plugs drilled at various angles to the lamination.
Results and Discussion

Evaluation of rock properties and fluid/rock interactions for the outcrop rock were performed for cores obtained from various outcrop locations in order to select suitable rock material for use in the 2D-rig experiments. Core material with high clay content was omitted from the tests due to potential tracer absorption problems. Core data, see Table 1.

Figure 4 shows a miscible brine/brine displacement where radioactive water, injected from the left, displaces the inactive water initially saturating the core.

After 1.15 PV of radioactive water is injected the core is 100% saturated with radioactive brine. Comparison to effluent profiles, Figure 5 and Figure 7, and to the process of replacing the radioactive brine with inactive brine, Figure 6, give information on adsorption, dispersion and capacitance. As can be seen by evaluating the miscible floods, a slight absorption takes place. The effluent concentration profiles show some capacitance; 50% concentration of radioactive brine
Table 1. Core Data.

<table>
<thead>
<tr>
<th>Core</th>
<th>Geological information</th>
<th>$\phi$ [%]</th>
<th>K [mD]</th>
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<tr>
<td>UC-08</td>
<td>Castlegate Formation, Lowermost part of Unit 1 in sequence 1, (fluvial deposits)</td>
<td>14.8</td>
<td>130</td>
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<tr>
<td>UC-16A</td>
<td>Castlegate Formation, Unit 2, sequence 1, (fluvial deposits)</td>
<td>16.4</td>
<td>110</td>
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<tr>
<td>UCP-2D</td>
<td>Castlegate Formation, Upper part in Unit 1, sequence 1, (fluvial deposits)</td>
<td>15.7</td>
<td>210</td>
</tr>
<tr>
<td>UCP-90</td>
<td>From UCP-block; drilled 90° to the bedding plane</td>
<td>15.5</td>
<td>5</td>
</tr>
<tr>
<td>UCP-45</td>
<td>From UCP-block; drilled 45° to the bedding plane</td>
<td>15.7</td>
<td>20</td>
</tr>
<tr>
<td>UCP-30</td>
<td>From UCP-block; drilled 30° to the bedding plane</td>
<td>15.9</td>
<td>120</td>
</tr>
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</table>


Experimental results from a drainage, i.e. oil displacing water, and a waterflood are found in Figure 8 and Figure 9. Fluids are injected from the left hand side in the figures. A substantial amount of throughput of oil is required to reduce the water saturation below 35%PV. It is evident from the saturation profiles in Figure 8 that the displacement mechanism before and after oil breakthrough is different. To obtain the low water saturation the capillary number has been increased by increasing the flow rate and using a high viscosity oil. End effects at endpoint drainage were reduced to insignificant levels, as seen in Figure 8, as a result of applying high capillary number flow conditions.

Figure 4. Radioactive brine displacing brine. Time is indicated in fractions of injected PV.

Figure 5. Effluent profile for radioactive brine displacing brine. UC-16A.

Figure 6. Brine displacing radioactive brine. Time is indicated in fractions of injected PV.

Figure 7. Effluent profile for brine displacing radioactive brine. UC-16A.
The waterflood is performed at low flow rate, the flow rate corresponds to a waterfront velocity of about 30 cm per day. The oil production was 27%PV, recovery efficiency was 34%, with a clean breakthrough after 27%PV of water had been injected, indicating strongly water wet conditions. The production profile based on effluent production matched the production data generated from in-situ fluid saturation measurements. This indicated true in-situ fluid saturation information.

The results from the miscible and immiscible floods in the collected heterogeneous sandstone indicated that the imaging technique was applicable for obtaining true saturation information. Thus it was decided to use material from this location in the 2D-imaging experiments. The slab of rock used for obtaining the 2D-model was also used to obtain three 1.5" diameter cores, cored at 30°, 45° and 90° angles respectively with respect to the bedding plane. Pictures of the three cores and the 2D-model are shown in Figure 1 and Figure 2.

![Figure 8](image1.png)

**Figure 8.** Drainage; oil displacing brine. Time is indicated in fractions of injected PV.

![Figure 9](image2.png)

**Figure 9.** Waterflood. Time is indicated in fractions of injected PV.

The three cores were brine saturated and oil flooded to a reduced water saturation of about 35%PV for all samples. The miscible brine/brine displacement, the drainage and the subsequent waterflood were imaged by the tracer technique. In Figure 10 the development of water saturation distributions during the waterflood are shown.

The water saturations after oil flooding are labelled $S_{wi}$ in the figure. The water saturations are measured in a 3 mm wide cross section of the core. Thus for a core laminated at an angle different than perpendicular to flow direction the cross sectional saturation information has contributions from various layers. Therefore 2D-imaging is required for detailed saturation information. However, we obtained some information on saturation development by 1D-imaging of the core displacements, as seen in Figure 10. Note in particular the two sets of saturation profiles for the core sample laminated at 45°. The second set of saturation profiles has been obtained when the collimator slit for the Germanium detector was turned 45°, i.e. parallel to the lamination. For the latter core the saturation information near the ends of the core is of course not representative, but in the central part of the core the saturation development in the individual laminae is imaged. A comparison between this information and the saturation profiles for the core with flow perpendicular to the lamination shows that the variation in brine saturation during waterflooding is not evident in the 45° laminated core. The significant variation in brine saturation exhibited in the flood perpendicular to the lamination has previously been reported, ref. 3,6,8 however, for this core part of the variation is due to porosity differences in the laminae. This has been cross checked with the porosity map of this particular core.

The recovery of oil by low rate waterflooding does not seem to be significantly influenced by the small scale lamination. The absolute permeability for the cores are affected by the lamination, it varies from 5 mD for the core with 90° lamination, to 20 mD for the 45° laminated core and to 120 mD for the 30° laminated core. We speculate, however, based on previous experience, that if each bedding had been wider, the interaction between the capillary forces and the small scale heterogeneity would cause trapping of oil, ref. 7. We therefore intend to proceed with experiments on cross-bedded rather than laminated sandstone.
For the reported experiments we did not succeed in finding cross-beddings of the desired thickness. The intention was to measure capillary pressure for each layer and thus to obtain a very detailed reservoir characterization.

The 2D-model was equipped with inlet and outlet ports on all sides. The objective was to allow for different flow directions. In the reported experiment flow was parallel to the laminae. The model was brine saturated and then flooded with radioactive brine. The miscible displacement was imaged and the dynamic process is shown in Figure 11; from left in the figure. The extension of the model is shown by the last image or by the picture of the model, Figure 2, or the permeability map, Figure 3. The uppermost part of the model seems to have preference for conducting flow and this correlates well with the permeability map of the model. The flow development is also due to the fact that the differential pressure per unit length is greater at the top of model than at the bottom due to the geometry of the model. The model was oil flooded at atmospheric conditions, timestep 1-5 in Figure 12, and then in a pressure vessel to obtain lower water saturation. The final in-situ fluid saturation distribution was measured at immobile water saturation, see last timestep in Figure 12.

Development of water saturation during the subsequent waterflood is shown in Figure 13. The initial water saturation, obtained after the oilflood, was 41%PV. The waterflood produced 22%PV oil corresponding to a recovery efficiency of 37%. Final water saturation was 63%PV. The in-situ saturation information shows the early formation of a waterbank with breakthrough at 0.22 PV brine injected. Comparing the results from the core floods, water breakthrough occurred at about the same time, independent of the angle of lamination. Water saturation development before water breakthrough shows that the high permeable region in the uppermost part of the model exhibits highest recovery, cfr. permeability map in Figure 3. When the waterbank reaches the outlet end, at 0.12 PV brine injected, water accumulates due to capillary end-effects and oil is recovered when water saturation increases towards the inlet end.

Figure 10. Waterflooding cores drilled at various angles with respect to the lamination: From top down: 90°, 45°, 45° (collimator slit turned 45°), and 30°.
The water advancement seems to be capillary dominated; the water saturation increases most rapidly in areas with low permeability, i.e. in the high capillary zones, cfr. the permeability map in Figure 3. Spontaneous imbibition from the lower part of the model where a water channel has developed, increase the water saturation towards the top of the vertically mounted model. No significant oil trapping due to the lamination is observed, however a small scale macroscopic oil trapping is observed due to the spontaneous imbibition.

Conclusions

1. The nuclear tracer imaging technique is found suitable for studying water and oil displacements in heterogeneous laminated sandstone from the Castlegate formation.

2. Enhanced description of miscible and immiscible displacements in laminated sandstone using the nuclear tracer imaging system has been obtained utilizing information on local in-situ saturation development.

3. Experiments evaluating the effect of various dip angles relative to the advancing water front in finely laminated sandstone indicate that the effective permeability depends strongly on the lamination angle.

4. For the selected laminated sandstone the water breakthrough and oil recovery by waterflooding were not significantly affected by the angle of the lamination.

5. Oil breakthrough during drainage was affected by the angle of lamination. Late breakthrough and highest water recovery was obtained with displacement transversal to the laminations.

6. Local 2D fluid saturation distributions have been obtained on a large slab of heterogeneous, laminated sandstone during miscible and immiscible displacements. 2D-imaging indicates an early viscous displacement followed by imbibition related to end-effects causing small scale macroscopic oil trapping.

*Figure 11. Time development of radioactive brine saturation when radioactive brine is displacing brine in the 2D-model.*
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References


Figure 13. Time development of brine saturation during the waterflood.


