MULTI-PHASE FLOW IN THE PRESENCE OF A FRACTURE TIP: EXPERIMENTS AND MODELING

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ABSTRACT

This paper focuses on multi-phase flow in the presence of a fracture tip. This work studies two-phase water-oil displacements in layered Berea Sandstones that have been artificially fractured with single extensional fracture perpendicular to the natural layers. Two experiments are considered in this paper. In the first experiment the fracture was induced at the inlet end of the sample and it spanned the first third of the core. Thus, the diverging flow at the tip of the fracture was studied. In the second experiment, the fracture was induced at the outlet end of the sample spanning about one third of the core, and multi-phase fluid convergence to the fracture tip was studied. The temporal and spatial saturation distributions of the two cases were determined using x-ray computed tomography, CT.

The experimental data were simulated. At the tip of the fracture, the two experiments showed different fluid flow patterns. The presence of the tip of the fracture in both experiments illustrated the displacement path in each layer. The presence of the fracture caused by-passing during the displacement process. From an experimental point of view, the presence of the fracture tip is essential for highlighting the property contrast between the natural layers in the sample, much more than in a displacement process without a fracture. Matches of the simulation results to the experimental data showed that when the fracture is at the inlet end, fluid diverges from the fracture to the matrix along the entire length of the fracture. The movement of the displaced phase was delayed in the regions neighboring the fracture and it preferentially flowed in the outer regions of the core.
Understanding multi-phase fluid flow in fractured rocks is essential for designing and optimizing hydrocarbon recovery processes. The fluid flow interactions between the fractures and the matrix have a significant impact on displacement processes. This work provides modeling results and experimental observations that explain some of the displacement processes around a fracture tip.

INTRODUCTION

Natural and artificially-induced fractures in a reservoir have a great impact on fluid flow patterns and on the ability to recover hydrocarbons. Fractures can have a negative effect on recovery process when they form bypass paths, especially in production-injection systems. For example, injected fluid may preferentially flow through the fractures leaving behind inaccessible and non-contacted hydrocarbons. It is important to understand the local and global effect of fractures on reservoir performance. In this paper, we are studying samples that have a single fracture and a fracture tip. The main goal of this work is to study the influence of the fracture tip on accentuating the hydraulic contrast between the layers during multi-phase flow and describe the fracture-matrix interactions.

Hydrocarbon recovery depends on the interaction between fluids in the fractures and in the matrix [1]. Inverse numerical modeling is expected to yield the fluid transport properties of the matrix and the fracture, and provide new analysis tools to directly relate four-dimensional saturation distributions to these properties.

PROCEDURE

Two experiments were conducted: one with the fracture induced at inlet end of the core, and one with the fracture induced at the outlet end of the core [2]. The fluid phases were benzyl alcohol and NaI-tagged water. The experimental procedure followed these steps:

A. The cores were fractured using a Modified Brazilian test method, Figure 1. Compression was applied to the rock sample using two opposed parallel jaws. Tension occurred normal to the plane containing the two jaw faces. The fracture propagated from the center, where the tensile stresses were greatest, to the outer edges, Figure 2.

Figure 1: Fracturing the core in the laboratory.

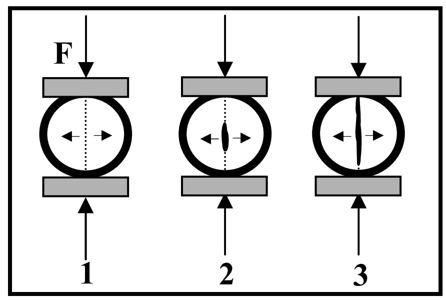

Figure 2: Modified Brazilian test.

B. The fractured core was put into the core holder and confining pressure was applied.

C. The dry sample was scanned. Figure 3 shows axial views of the samples.

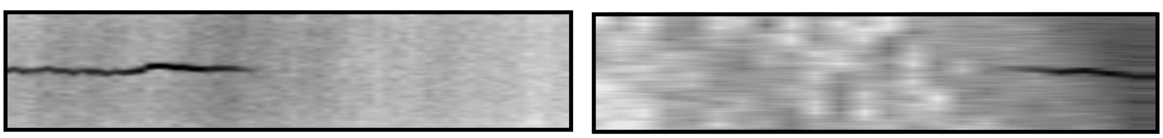

Figure 3: Axial views of the two cores after fracturing. Left: inlet. Right: outlet.

D. The sample was evacuated and saturated with water. Absolute permeability was measured. The samples were scanned at the same positions of the dry scans.

E. Porosity distribution was calculated and using Timur's permeability correlation, the absolute permeability distribution was calculated to yield an overall match to the experimentally derived absolute permeability [3]. Figure 4 shows a typical porosity images highlighting the layered nature of the sample. Three specific layers 8, 9, and 10 are
discussed later in the paper.

F. Oil was injected into the sample and several scanning sequences were acquired. Figure 5 shows images at different values of pore volumes of oil injected.

G. Water was injected into the sample and several scanning sequences were acquired during the injection period.

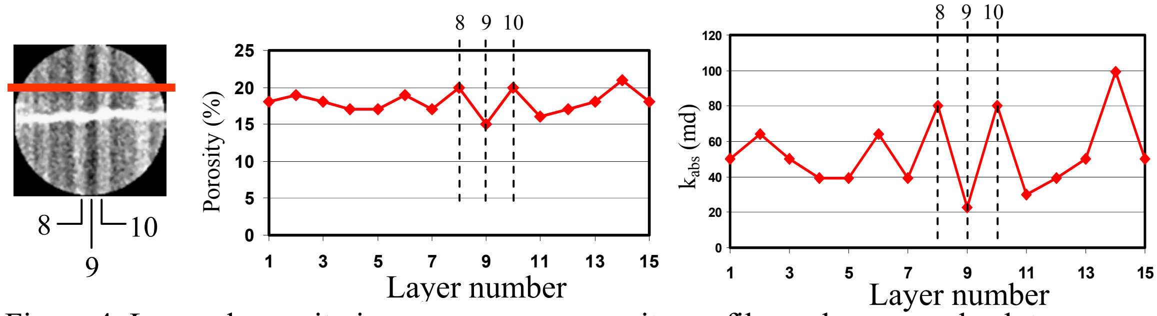

Figure 4: Layered porosity images, average porosity profile, and average absolute permeability profile.

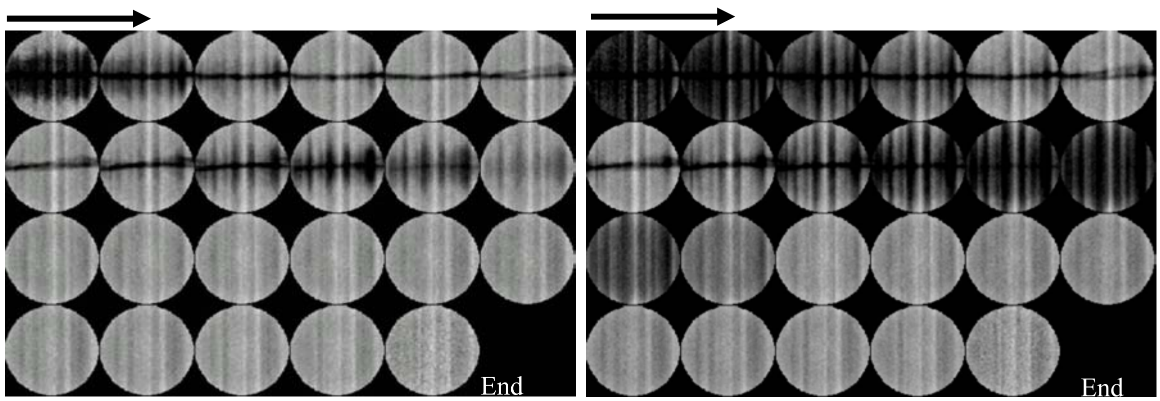

Figure 5: Images at two oil injection stages. Left: 0.051 PVOI. Right: 0.212 PVOI.

H. Figure 6 shows the grid system for a single layer of the core as part of a three dimensional multi-layer model. The experiments were modeled using a reservoir simulator (Eclipse) that was coupled to an automated history matching technique.

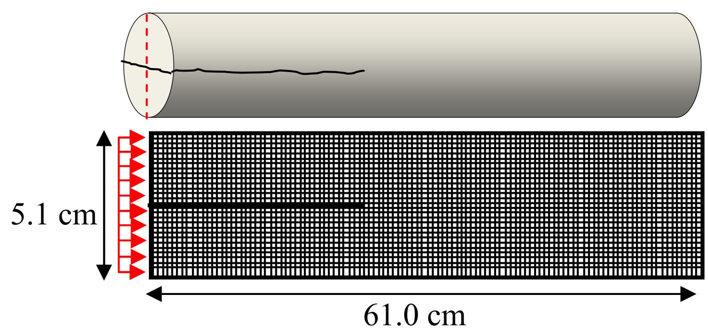

Figure 6: Simulation grid system. Grid: 51X610.

RESULTS AND DISCUSSION

The model provided excellent matches with the experimental data. It captured the two-phase fluid flow behavior in the fractured region and away from it. Figure 7 shows experimental and simulation axial sections of oil invading into a water-saturated core. The simulation results were analyzed to determine the influence of the fracture tip on the two-phase fluid flow processes. Figure 8 shows reconstructions of the oil flood at 0.212 PVOI and the flow path of the oil. The oil diverged away from the fracture due to the presence of the fracture tip, which influenced the fluid to flow vertically along the fracture. At the tip, the fluid flow transformed from horizontal (in the fracture) to vertical and back to horizontal (in the matrix). The vertical flow above and below the fracture accentuated the hydraulic contrast between layers. Above and below the fracture, the high k and ϕ layers are displaced early in comparison to the low k and ϕ layers. Figure 9 shows profiles above the fracture in the region of the fracture tip. Behind the fracture tip, the vertical flow component magnified the layer contrast as shown in the middle three layers. Ahead of the fracture tip, the layer contrast was not as pronounced due the horizontal flow in the non-fractured region and the capillary equilibrating forces between the layers. A simulation test was done for two layers; one with high k and ϕ values and one with low k and ϕ.

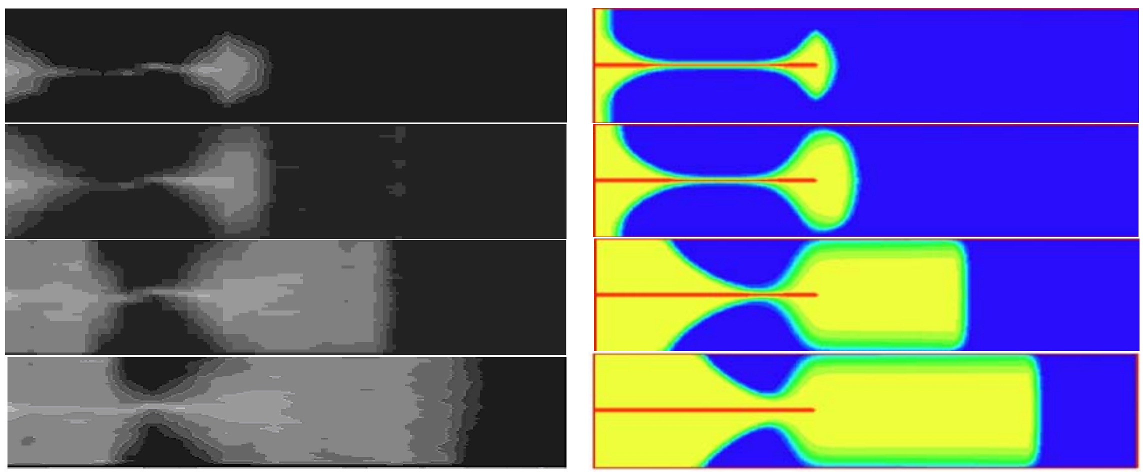

Figure 7: Experimental and Simulation axial maps of four stages during the oil flood.

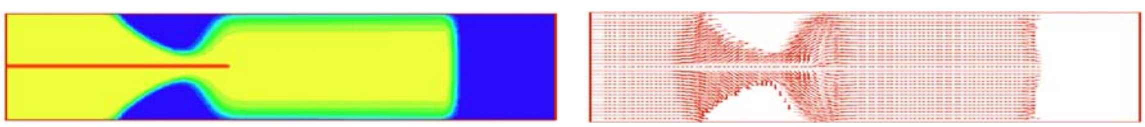

Figure 8: Simulated oil flood showing the flow paths in the system.

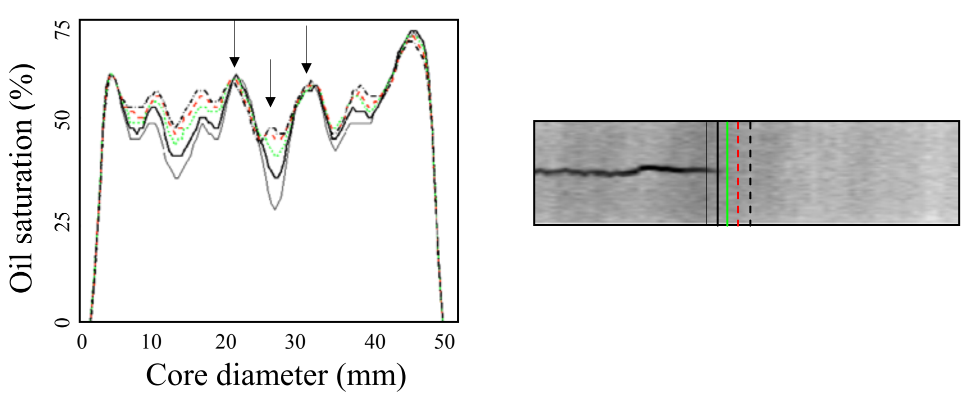

Figure 9: Cross section profiles of oil saturation at the fracture tip region.

The inter-layer permeability was varied between zero and the specific permeability of the layer at a given position. Figure 10 illustrates the saturation of the high and low k and ϕ layers for different values of cross-layer permeabilities. At the inlet side, due to capillary forces and co-mingling at the fracture, the displacement front in the high k and ϕ layer retreated and in the low k and ϕ advanced. At the fracture tip region the saturation increases in the high k and ϕ layer and decreases in low k and ϕ layer. At the tip region when inter-layer communication is established, the vertical flow components in the fracture tend to fill the high k and ϕ layer then fill the low k and ϕ one. At the fracture tip, the convection forces are more dominant than the capillarity forces and the high k and ϕ layer has higher saturations than the low k and ϕ layer, thus confirming that the fracture tip accentuates the contrast between the layers.

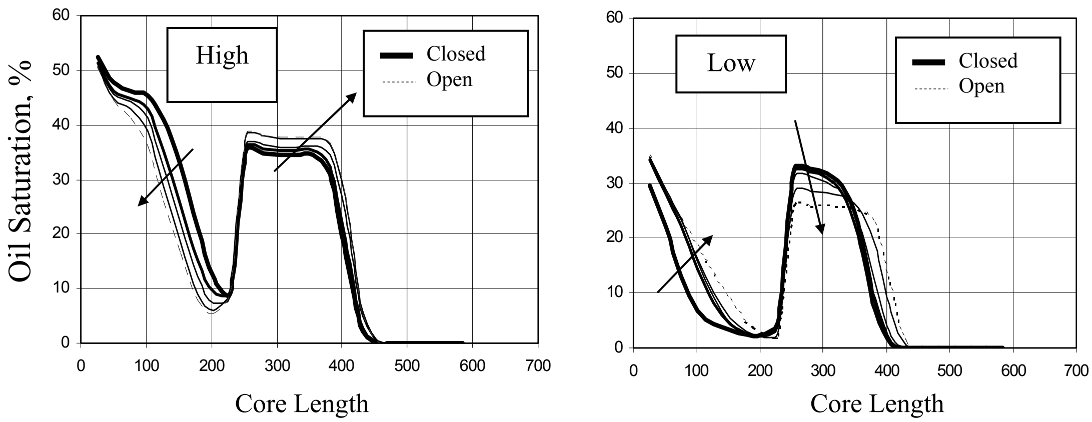

Figure 10: Average axial saturation profiles. Left: high k and ϕ. Right: low k and ϕ.

Figure 11 shows oil profiles at different pore volume injected. It shows two different influence of the fracture tip on the fluid saturation around it. In the first experiment, the area around the tip reached residual values faster than any other location in the core. In the second experiment where the fracture is at the outlet end of the core, the area around the tip retained water for a long period of time while the oil converged to the tip and flowed downstream in the fracture.

CONCLUSIONS

The distribution of the oil and water saturations was computed from the CT data. A commercial numerical simulator (Eclipse) was used to successfully simulate the experiment. This work concludes that the displacing fluid diverges along the fracture due to the presence of the tip of the fracture when the tip is located downstream. The fracture tip also accentuated the hydraulic contrast between the layers. The by-passed fluid is displaced away from the fracture and forced to flow along the edges of the sample. The path of least resistance in the matrix next to the fracture is fluid-depended. In the two experiments the fracture tip influenced the flow differently.

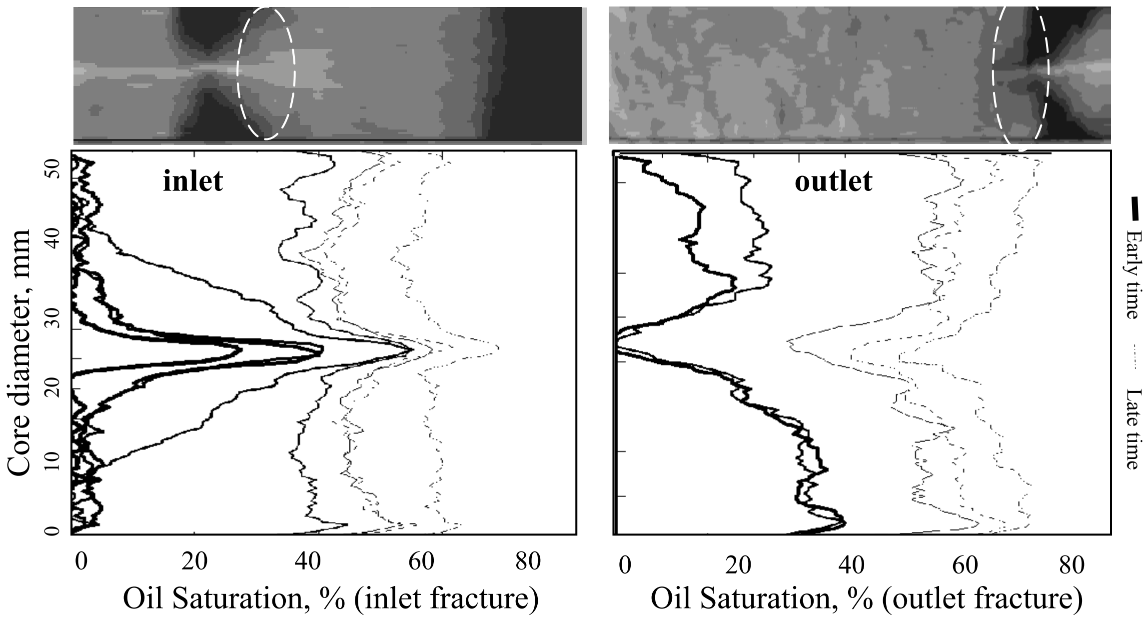

Figure 11: Vertical oil saturation profiles at different pore volume of oil injected for the two experiments. Left: inlet fracture. Right: outlet fracture.

REFERENCES

1. Grader, A. S., Balzarini, M., Radaelli, F., Capasso, G., and Pellegrino, A., Fracture-Matrix Flow: Quantification and Visualization Using X-Ray Computer Tomography. Symposium on Dynamics of Fluids in Fractured Rocks. Lawrence Berkeley National Laboratory, Berkeley California, February 1999.
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