



Contribution ID: 782

Type: Oral Presentation

## Microfluidic investigation of phase banking during low tension displacements

Thursday, 3 June 2021 19:45 (15 minutes)

During low tension displacements, aqueous surfactants are injected into porous rocks to mobilize trapped oil or non-aqueous phase liquids (NAPLs). The trapped ganglia move and form aggregations (banks) that are a considerable fraction of the flow domain (~0.1 to 0.5 domain length). Formation of phase banks during low tension displacements has been widely observed in corefloods in the context of enhanced oil recovery and NAPL remediation. Additionally, fractional flow theory provides a macro-scale explanation for the formation of banks: if the velocity of the saturation of the oil bank is larger than that of the injectant, a bank should form. However, the pore-scale mechanics of banking are not clear and have not been widely investigated, likely because banking appears to be scale dependent and most direct-imaging platforms capture small flow domains. Why do oil ganglia coalesce and move as a bank, rather than as individual ganglia? How are the surfactants distributed within and around the bank? Using a novel microfluidic platform, a “coreflood on a chip”, we visualize aqueous surfactant solution displacing oil at varying viscosity ratios and try to answer these questions. We find that banks may form at very unfavorable viscosity ratios, and the presence of surfactant in a region at the rear of the bank is necessary for the oil bank to form.

The coreflood-on-a-chip is a glass micromodel that is 1.2ft long, has a heterogeneous pore structure, and includes shallow, 2.5D pore throats (Mejia et al., 2020). Our experiments involved injecting brine (30,000 ppm Na<sub>2</sub>CO<sub>3</sub>, 1 cp) into the micromodel, displacing the brine with a viscous crude oil from the Alaskan North Slope (0.81 g/cm<sup>3</sup>, 83 cp), displacing the crude oil with 30,000 ppm Na<sub>2</sub>CO<sub>3</sub> until residual oil saturation was reached, and finally injecting aqueous surfactant solution (mixture of a sulfate anionic surfactant, an internal olefine sulfonate, and IBA) continuously. We adjusted the viscosity of the surfactant solution by including hydrolyzed polyacrylamide (HPAM) to achieve viscosities of 1 cp (without polymer), 40 cp (with 2400 ppm polymer), and 90 cp (with 3600 ppm polymer). The water-oil displacements were conducted at 8 ft/day, while the surfactant solution-oil displacements were conducted at 4 ft/day. Whole domain images were captured using a digital single lens reflex camera, and pore-scale images were captured using a stereomicroscope. Results from the whole domain images were interpreted using fractional flow theory, and discrepancies between experimental results and the model are explained using the microscopic images. Furthermore, we conduct pore-scale simulations using the Volume of Fluids (VOF) method in a simple geometry to interpret the experimental results recorded using the stereomicroscope.

Our experiments show some surfactant must be present at the rear of the oil bank to initiate its formation. Moreover, the distribution of surfactant solution is more nuanced than that described by fractional flow; some surfactant is present within the oil bank. Finally, the pore-scale simulations indicate radial dispersion of oil and interfacial tension gradients (at the pore-scale) are important mechanisms for bank formation.

### Time Block Preference

Time Block C (18:00-21:00 CET)

### References

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**Session Classification:** MS6-B

**Track Classification:** (MS6-B) Interfacial phenomena in multiphase systems