Miscible or Immiscible? Gas Flooding for Bakken Reservoirs in Southeast Saskatchewan

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Summary

This experimental study compared the effectiveness of miscible or immiscible gas flooding processes using four injection gas candidates (i.e., CO_2, CO_2-enriched flue gas, oilfield-produced gas, and nitrogen) for unconventional Bakken tight oil reservoirs in southeast Saskatchewan. The results demonstrated that CO_2 had the lowest MMP and largest viscosity reduction and oil swelling among all the tested gases. Therefore, CO_2 flooding is technically feasible as a miscible process at the current reservoir conditions, while the use of the other three gases would result in an immiscible process.

Method

An integrated experimental methodology was adopted to evaluate phase behaviour and oil recovery performance of four gases for the largest Viewfield reservoir in southeast Saskatchewan Bakken formation (Luo et al., 2017). The phase behaviour of the live oil–gas systems was studied through pressure/volume/temperature (PVT) tests and equation-of-state modeling. Since miscibility between the oil and injected gas is known to improve the displacement efficiency, the MMP values for the live oil–injected gas systems were determined using the rising bubble technique. To investigate geochemical interactions of CO_2 with Bakken cores, scanning electron microscopy with dispersive X-ray spectroscopy (SEM-EDS) was used to observe the surface morphology of cores and identify minerals on the rock surface before and after long-term exposure to CO_2-saturated formation brine at reservoir conditions. Finally, four coreflood tests using reservoir core plugs and recombined reservoir live oil were used to examine the displacement performance of the four gases.

Results and Conclusions

The phase behaviour tests showed that CO_2 was superior to the other three gases tested (CO_2-enriched flue gas, produced gas, and nitrogen) in terms of solubility, viscosity reduction, and oil swelling (Fig. 1). A significant amount of CO_2 could be dissolved into the oil phase at slightly elevated pressure. Produced gas could also dissolve into the Bakken live oil and reduce its viscosity, although not as significantly as CO_2. On the other hand, CO_2-enriched flue gas and nitrogen had rather lower solubility in oil, so that their effects on reducing oil viscosity were very weak. On the other hand, dissolution of cementing calcite/dolomite could lead to framework reorganization, i.e., dislodged framework grains such as feldspar and quartz or clays leading to blocked pore-throats (Fig. 2). As a result, the reservoir properties, particularly permeability, could be affected by these interactions and in turn have a considerable impact on the long-term CO2 flooding and storage performance (Luo and Coulson, 2014).

The RBA test results demonstrated that the MMP between the live oil and CO_2 was 11.9 MPa, while the MMP between live oil and flue gas, produced gas, and nitrogen was considerably higher than 30 MPa. These results indicate that CO_2 flooding can easily reach a miscible condition in the field, whereas injection with other three gases will always be under immiscible conditions. The oil displacement efficiency was greatly improved by flooding with CO2 compared to other gases (Fig. 3): the enhanced oil recovery stages (gas injection and extended waterflood) of a coreflood using CO_2 recovered 75.8% of the residual oil in place (ROIP), whereas the corresponding stages for CO_2-enriched flue gas and produced gas recovered 47.7% and 47.8%, respectively.

The experimental results reveal that CO_2 can be an effective EOR injectant for southeast Saskatchewan Bakken tight oil reservoirs and offer the potential for significant greenhouse gas storage (Hoffman, 2012; Liu et al., 2014). As follow up of this work, several innovative laboratory technologies have been developed for tight core analysis and EOR evaluations. These include simultaneous capillary pressure and relative permeability determination using centrifuge, large-scale dual-permeability coreflood model; coreless injectivity test, pulse pressure permeability measurement, water chemistry coupled geochemical modeling.

Acknowledgements

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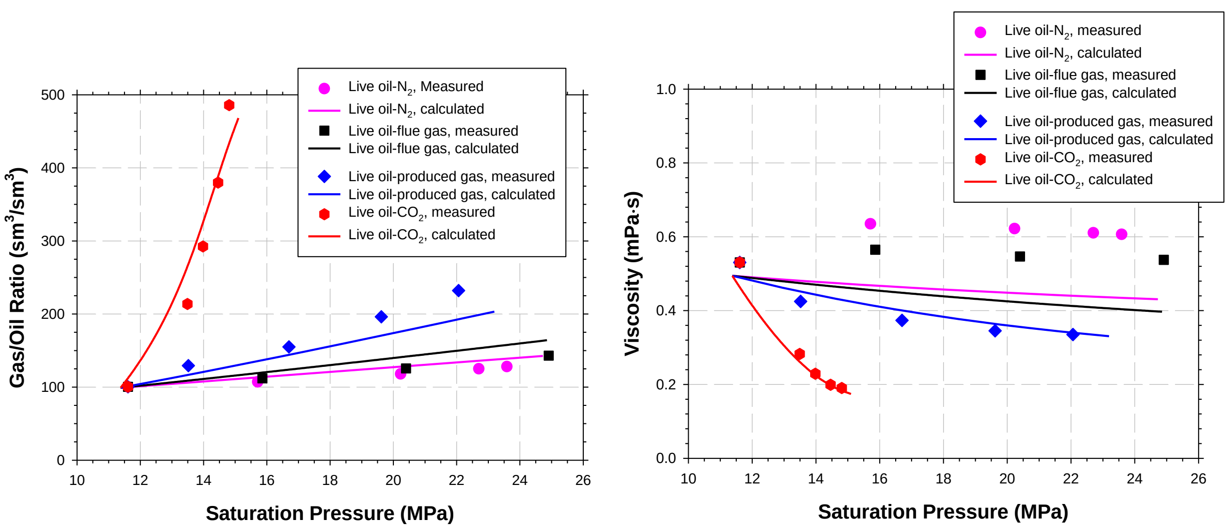
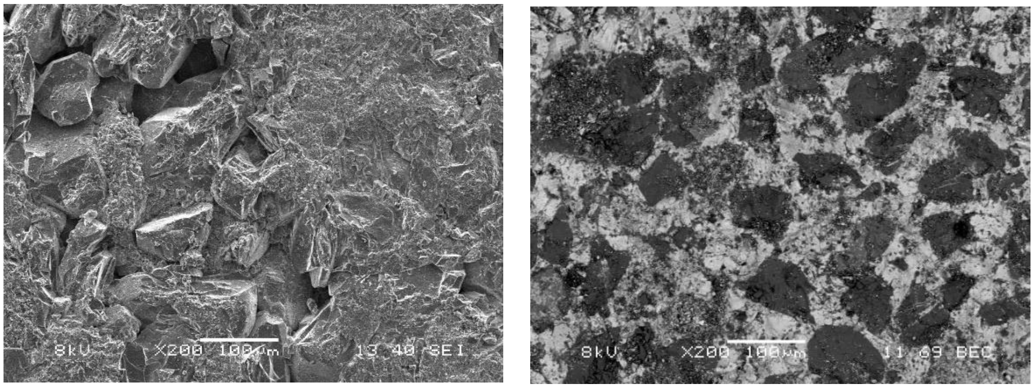
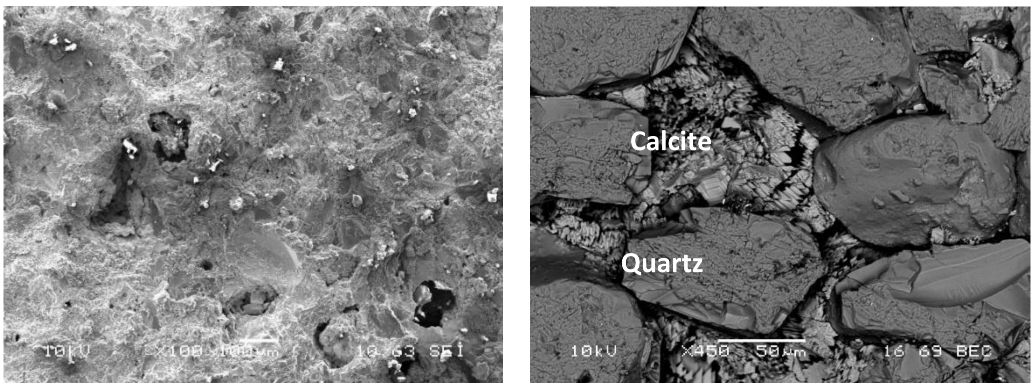


Fig. 1. Measured and calculated viscosities of Bakken live oil with different gases.



(a) Before saturation



(b) Two months after saturation

Fig. 2. SEM images of Bakken rocks before and after reactions with CO_2-saturated formation brine for two months.

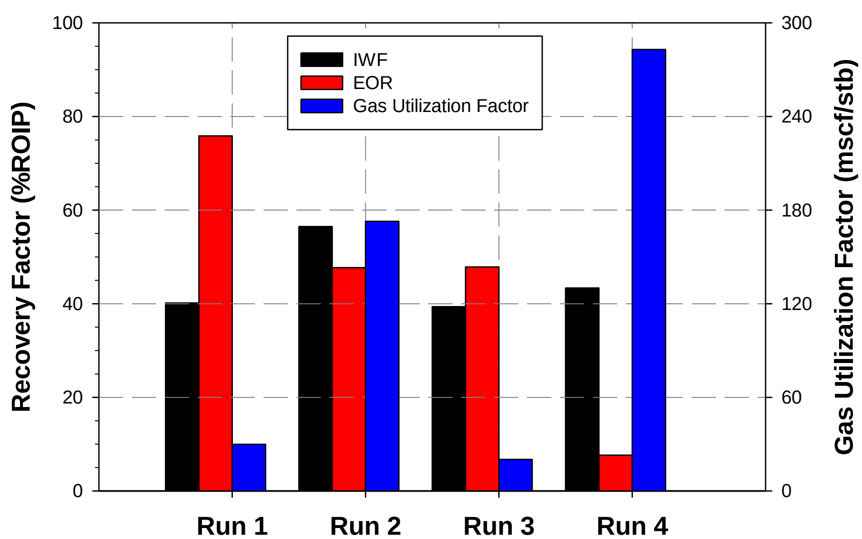


Fig. 3. Comparison of recovery efficiencies of four corefloods using different injection gases (Run 1: CO_2; Run 2: CO_2-enriched flue gas; Run 3: Produced gas; Run 4: Nitrogen)