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Effectiveness of supercritical-CO_2 and N_2 huff-and-puff methods of enhanced oil recovery in shale fracture networks using microfluidic experiments

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HIGHLIGHTS

- Supercritical CO_2 huff-and-puff injection can significantly increase recovery in shale.
- Gas injection is more effective in connected fracture networks.
- Microfluidic visualization method reveals the mechanisms of bubble nucleation, growth, and coalescence in fracture networks.
- The efficiency of the huff-and-puff process is dependent on the solubility and miscibility of the injection fluid with oil.

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ABSTRACT

Current oil recovery methods in hydraulically fractured shale reservoirs have a low recovery efficiency of about 10%. The objective of this work is to investigate the effectiveness of nitrogen and supercritical carbon dioxide in the huff-and-puff method for enhanced oil recovery as a means to re-energize reservoirs and improve recovery rates. We conduct direct visualization experiments with a microfluidic system to reveal the mechanisms and to quantify the recovery rates of oil from fracture networks. We compared the effectiveness of water, nitrogen and supercritical carbon dioxide at reservoir conditions in a process mimicking the huff-and-puff method in both dead-end and connected fracture systems. The microfluidic chips were made of glass and placed in a confining pressure system pressurized to 10 MPa, 50 °C. The system was allowed to equilibrate, and then depressurized to simulate huff-and-puff oil recovery. Fluorescence microscope images were continuously taken to visualize and calculate residual oil saturation as a function of pressure drawdown. As the system was depressurized from 10 MPa, gas exsolution from the oil liquid phase, including bubble nucleation, growth, and coalescence, appeared to be the main driver for mobilizing oil from the fracture networks. Injection of supercritical CO_2 resulted in the highest recovery rate with an average end-point recovery of about 90% in the connected fracture network and 60% in the dead-end fracture network. N_2 has lower solubility in oil and hence showed a lower recovery rate of 40% in the connected fracture network and 25% in the dead-end fracture network. Injection of water had no effect on oil mobilization since water is insoluble, immiscible and incompressible. The main mechanism of enhanced recovery was gas exsolution from the liquid phase as pressure was decreased below the bubble point pressure. Because the gas was distributed throughout the oil phase, bubble nucleation, growth, coalescence, and elongation occurred throughout the fracture network. Expansion of the gas forced oil out of the network through piston displacement in continuous oil areas and film flow in the dispersed oil areas. Bubbles began as spheres and grew until they touched the fracture walls where they elongated along the fracture length. The bubble growth rate depended on local mass transfer from liquid to gas phase and gas volume expansion due to pressure drop. The efficiency of the huff-and-puff process is dependent on the solubility and miscibility of the injection fluid with oil. High gas solubility allows for more bubble nucleation, growth and expansion during the depressurization cycle.

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1. Introduction

Shale hydrocarbon reserves are large worldwide with a total of 7600 trillion cubic feet of gas and 419 billion barrels of oil (US Energy Information Administration (EIA) 2015) [1]. The US currently has the largest shale oil and gas reserves in the world with 630 trillion cubic feet of gas and 80 billion barrels of tight oil (EIA 2015). However, the current technology based on hydraulic fracturing and horizontal drilling has a recovery rate of about 10% for liquids and 20% for gas [2–6]. The production rate also declines rapidly within the first few years. These low production rates have negative impacts on the economics and exacerbate environmental issues facing the long-term development of this energy resource. Current research efforts are directed towards improving recovery rates with enhanced production processes that can reduce the number and density of wells.

Methods for enhanced hydrocarbon recovery in shale include gas injection of CO_2, N_2, and natural gas using techniques known as huff-and-puff. Many laboratory studies have examined gas injection in shale core samples and found additional oil and gas can be recovered [7–11] These studies have considered the effects of injection pressure and miscibility on recovery performance [12]. The recovery rates were determined by weighing the shale core plugs before and after injection tests with reported oil recovery rates of up to 80% by the CO_2 huff-and-puff method. However, the mechanisms of enhanced recovery in these experiments were not visualized.

Recently, a field-scale test of CO_2 injection into a shale reservoir in Morgan County, Tennessee was conducted for both CO_2 storage and enhanced gas recovery [13]. This study injected 510 tons of CO_2 for two weeks, soaked for 4 months, and then started enhanced recovery. The production rate was 8 times higher than before CO_2 injection and extended production by an additional 15 months. Reservoir simulations of CO_2 huff-and-puff in shale reservoirs conducted by several groups have predicted increased oil recovery by 30% and extended reservoir life by 15 years [14–18].

In this study, we use microfluidic techniques to shed light on the detailed mechanisms that control enhanced hydrocarbon recovery. Microfluidics experiments have been widely used in chemical and biological research and have recently been adapted for subsurface geoscience and engineering applications to study a number of oil recovery methods including CO_2, steam, polymer, and nitrogen [19–24]. These methods have also been used for measuring fluid properties and miscibility pressures [25–27]. Microfluidics has the advantage of providing direct visualization of the mechanisms occurring at the pore scale with high spatial and temporal resolution. Micromodels are typically made of silicon, glass or plastic with experiments conducted at ambient temperature and pressure. We have recently adapted microfluidics for geomaterials such as rock and cement at pressures and temperatures that simulate reservoir conditions [21]. In this paper, we use microfluidics to examine the relative effectiveness of CO_2, N_2, and water injection for enhanced oil recovery (EOR) at reservoir conditions in glass micromodels with future work planned to explore these working fluids in shale micromodels.

There are three main physical processes that occur in gas-injection EOR in shale fractures as the reservoir is produced and pressure falls: gas expansion in the fracture network, gas exsolution from oil trapped in the fracture network and hydrocarbon desorption from the shale matrix. This paper focuses on gas expansion and exsolution processes, which have been previously studied in conventional and heavy oil solution gas drive oil recovery methods, however detailed mechanisms of these processes have not been studied for fracture systems. For example, Bora et al. [28–30] conducted micromodel studies of the solution gas drive process in etched glass micromodels representing porous media to study the pore-scale physics of bubble nucleation, growth, and coalescence and pore-scale flow behavior. The initial pressure and temperature conditions for the live oil used in the experiments were 3.1 MPa and 23 °C. Their study showed that bubble nucleation in porous media was induced by supersaturation of gas pressure and bubble nucleation was not instantaneous but was progressive. For slow depressurization rates, bubbles grew in size to occupy several pore spaces. For fast depressurization rates, bubbles grew in one pore and

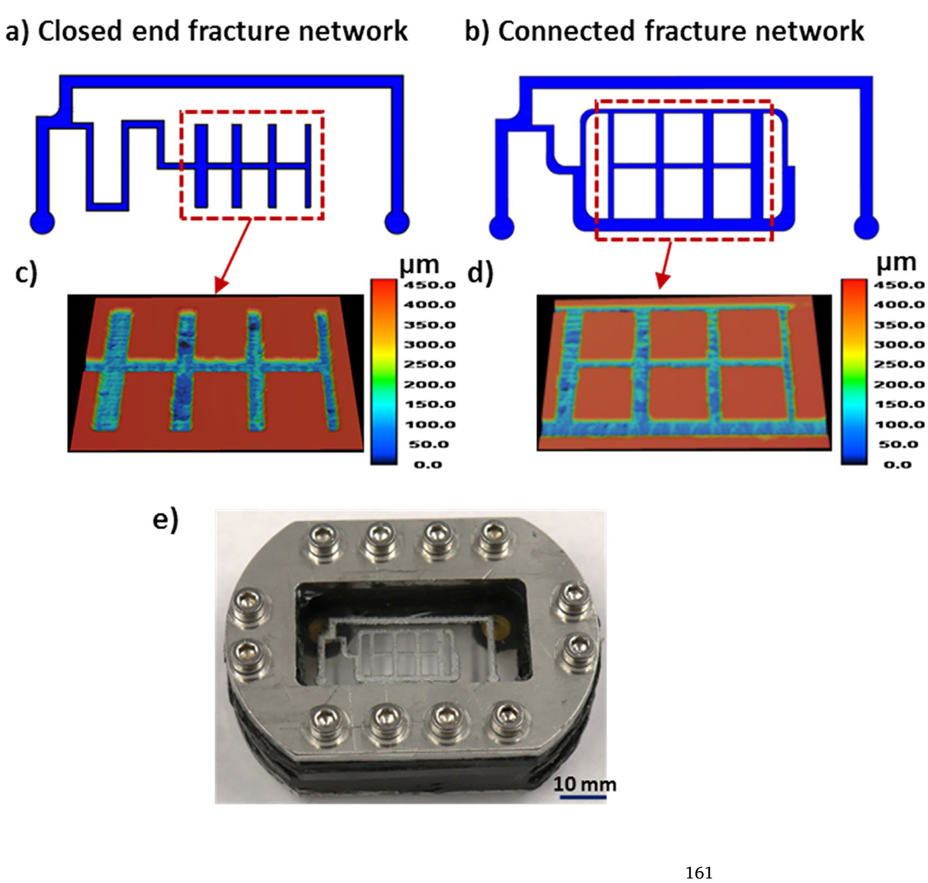

Fig. 1. Fracture network patterns and chip assembly (a) dead-end fracture system, (b) connected fracture system, (c) profilometry image of the etched chip with a dead-end fracture pattern with color bar indicating channel depth, (d) profilometry image of the etched chip with a connected fracture pattern with color bar indicating channel depth, and (e) photograph of the chip assembly. The chip dimensions were 25.6 × 46.3 mm.