

Enhanced Hydrocarbon Recovery in Low-Permeability Reservoirs using Surfactants: An Integrated Rock and Fluid Study

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Introduction / Novelty

Commercial production of low-permeability liquid-rich gas reservoirs has become viable through the application of multi-fractured horizontal wells. However, hydrocarbon recoveries remain exceedingly low (<5-10%) using the primary recovery scheme. As a result, operators have investigated the use of 1) enhanced recovery techniques such as cyclic gas injection (e.g., [Hoffman and Reichhardt, 2019](#)) and/or 2) chemical additives such as surfactants (e.g., [Druetta et al., 2019](#)) and nanoparticles (e.g., [Zhang et al., 2014](#)) to improve hydrocarbon recovery. For testing chemical additives, spontaneous recovery experiments have been proposed as a simple, fast and cost-effective screening approach (though not fully representative) to allow the investigation of controlling mechanisms and factors. Experimental spontaneous recovery studies with surfactants are extensive, with seminal examples, providing insight into the fundamental mechanisms and controlling factors at pore (e.g., [Zhang et al., 2020](#)), core (e.g., [Habibi et al., 2020](#)) and field (e.g., [Farajzadeh et al., 2021](#)) scales. However, these studies are primarily focused on rock analysis, with much less attention given to fluid analysis. In particular, the dynamics of the surfactant-aided recovery processes over extended periods (i.e., months) has not been explored in the previous laboratory studies. The current study work presents results from an integrated rock and fluid experimental study, investigating the dynamics of surfactant-aided recovery processes in low-permeability liquid-rich gas reservoirs. The primary objective is to predict the impact of rock-fluid-surfactant properties on the 1) recovery rates and the ultimate recovery factors and 2) compositional evolution of the produced hydrocarbons over short (i.e., days) and long (i.e., months) periods.

Samples / Methods / Workflow

In total, nine core plugs with 2.5–3.8 cm (1, 1.5") diameter and 2.8–5.3 cm (1.1–2.1") length were analyzed in this study. These core plugs were drilled parallel to bedding from a 50m core interval obtained from a vertical well completed in low-permeability liquid-rich gas intervals of the Montney Formation in western Canada. The samples were subjected to a comprehensive suite of screening geochemical and petrophysical analyses, serving as important reference points for the current study. The selected samples have relatively similar geochemical and petrophysical properties, representing a typical producing unit within the Upper Montney Formation with the following ranges of key properties: TOC content: < 1 wt.%, clay content: 15-18%, quartz content: 37-42.0%, carbonate content: 17-26%, helium porosity: 5.3-7.4%, mean pore throat size (10-35 nm), and profile (N₂) permeability: 0.004-0.012 md.

The experimental procedure for spontaneous recovery testing using surfactants included two primary stages: 1) spontaneous imbibition with dewaxed formation oil and 2) spontaneous recovery with tap water and synthetic brine (reproduced based on the produced water salinity) using three different commercial surfactants with similar concentration (1 cc/L). During stage 2), gas chromatography – mass spectrometry

(GC-MS) of whole-oil was performed to determine the molecular composition of the produced hydrocarbons after 65 days and 6 months of recovery (both sub-sampled from the same recovered oil volume) to track the compositional evolution over short and long periods. The surfactant experiments were benchmarked against three blank experiments using tap water, field brine and synthetic brine with no surfactants.

Key Results / Observations

Experimental observations indicate that the rate of oil imbibition and ultimate imbibed oil volumes are controlled by micro/mesopore specific surface area, micro/mesopore volume and the pre-existing fractures. For samples with comparable reservoir quality, the recovery rates and the ultimate recovery factors are controlled by the types of surfactants and carrier fluid (i.e., tap water vs. synthetic brine). The composition of produced hydrocarbons, sub-sampled after 65 days and 6 months, vary for different rock, surfactant and carried fluid systems. The higher the recovered oil volume, the higher the concentrations of C₇-C₁₂ components in short-term production (after 65 days). The use of surfactants significantly (up to an order of magnitude) increases the concentration of C₇-C₁₂ components, depending on the oil/surfactant solubility and the type of carrier fluid (water, brine). After long-term production (after 6 months), heavier components (C₁₃-C₃₁) are relatively enriched, particularly for the samples with the highest recoveries. Comparing compositional data after short- and long-term production periods, it is evident that the commonly used compound ratios (i.e., saturate biomarkers) do not change over the recovery period, whereas some volatile aromatics are altered. Therefore, when performing EOR using surfactants, geochemical analysis based on aromatic hydrocarbons may not be reliable and only ratios of saturate compounds should be used. The findings of this study will be beneficial to operators developing the low-permeability reservoirs within the Montney Formation by allowing them to optimize the production and fluid testing programs over short and long recovery periods.

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