# Modeling fluid migration and distribution in unconventional reservoirs; an example from the Montney Formation, British Columbia, Canada

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## Summary

Unconventional reservoirs are characterized by low permeability and generally require special well completion methods to obtain economic flow rates. One striking feature common to unconventional reservoirs is unpredictable fluid distributions, in which higher density fluids may overlie lower density fluids (for example oil over gas), in contrast with conventional reservoirs that exhibit lower-density fluids overlying higher-density fluids. Controls exerted by fluid properties and petrophysical properties on fluid distribution are poorly understood, but we propose that petrophysical properties (pore size, pore throat size, wettability) combine with fluid properties (density, surface tension) to determine hydrocarbon migration in low porosity systems with small pores. Capillary pressure is the main constrain to migration: because of surface tension effects, a higher pressure is required for gas to enter a pore compared to oil. Therefore, we expect gas to enter only rock types with the lower capillary pressure.
We test models for fluid distribution in an unconventional reservoir by simulating the migration of the hydrocarbons in the reservoir at the Septimus field of the Montney Formation (British Columbia, Canada), where oil is present up-dip of gas. Different scenarios will be tested, some of which will apply parameters based on Septimus Field data, including variable timing of charging events and different compositions and properties of fluids entering the reservoir.

## Introduction

The Lower Triassic Montney Formation is one the most important plays of North America (Seifert et al., 2015; Proverbs et al. 2018), the most important unconventional reservoirs of the Western Canadian Sedimentary Basin (Owen et al., 2020) and one of the most important siltstone reservoirs in the world (Vaisblat et al., in press) with estimated reserves of 459 TCF gas, 14,521 MBBO of natural gas liquids and 1,125 MMB of oil (National Energy Board, 2013). The formation covers an area of 130 000 km$^2$ in southwestern Alberta and northeastern BC (Vaisblat et al., in press) and can reach a thickness of up to 350 m in British-Columbia (BC) and becomes thinner to the east (Rohais et al., 2018; Wood et al., 2018). The lithology of the Montney is dominated by dolomitic siltstone, locally with very fine-grained sandstone (Zonneveld and Moslow, 2018; Vaisblat et al., in press). In northeastern BC, some oil and gas fields of the Montney Formation present unusual fluid distributions, with gas pools either overlain by water-saturated layers (Wood, 2013) or, the major focus of this study, gas pools overlain by oil pools. By applying numerical models to hydrocarbon migration in an oil and gas field of the Montney Formation, it is possible to test the roles of the fluid properties and petrophysical properties in controlling the fluid distribution within the reservoir.

## Dataset and Methods

Gamma-ray, neutron porosity and density logs from 15 wells of the Septimus field were used to conduct a probabilistic cluster analysis with the GAMLS software to identify four modes that correspond to rock-type end members. Samples from the different modes were subjected to a suite of mineralogical, geochemical and petrophysical analyses (Hernandez et al., 2020). Each mode is characterized by distinctive mineralogical compositions, organic carbon content, rock fabric and petrophysical properties that include pore-throat size. These in turn result in capillarity entry pressures that vary between the modes. Petrophysical properties and fluid properties are accounted for in the modelling of hydrocarbon migration. Modelling is accomplished using Permedia® software that applies the invasion-percolation theory (Carruthers, 2003) to the simulation of complex fluid-migration processes under the influence of both capillary and buoyancy forces.

## Research Directions

During hydrocarbon migration, buoyancy is the driving force and is resisted by capillary forces (Schowalter, 1979; Carruthers, 2003); as a result, capillary pressure being one of the main constraints to oil migration (Carruthers and Ringrose, 1998; Carruthers, 2003). In unconventional reservoirs, when capillary entry pressures become extremely high, we expect to see a segregation of fluids controlled primarily by capillary pressure and rock facies. We test this model at Septimus field, an oil and gas accumulation in the Montney play in which a distinctive segregation of hydrocarbon types is observed.

To test the roles of petrophysical and fluid properties in controlling fluid distributions in the Septimus field, a suite of flow simulations is developed, applying petrophysical data acquired by Hernandez et al. (2020). For each rock type, Hernandez et al. (2020) determined specific capillary entry pressure. Lithologies are created within Permedia® using these data. For each simulation, the reservoir is considered to be initially saturated with water. In the simulations, the reservoir will first be charged with oil and subsequently charged with gas to observe the effect of the capillary pressure and rock facies on the fluid distribution.

As the work progresses and models improve, more data will be added to the model to reflect the heterogeneity and complexity of the Montney Formation. Different scenarios will be tested, some of which will apply parameters based on data collected in the Septimus field, including variable timing of charging events and different compositions and properties of fluids entering the reservoir. Some parameters will be varied outside the limits of Septimus field data to explore factors that differentiate conventional from unconventional reservoirs.

## Conclusion

This study applies a combination of field data, petrophysical data and numerical modelling to develop constrains on parameters controlling the fluid distribution in the Montney Formation. This project will lead to new models for hydrocarbon migration and distribution in unconventional reservoirs. Our models could help to predict the hydrocarbons present in unconventional plays, saturation, and producibility within unconventional petroleum systems and therefore could reduce the risk and the cost of exploitation of these resources. The insights gained on this project may apply to low permeability oil and gas reservoirs elsewhere.

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