Example of Fluid Migration and Distribution Modelling in Unconventional Reservoirs from the Montney Formation, Northeastern British Columbia (NTS 093P, 094A)

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Introduction

Unconventional reservoirs are characterized by low permeability and generally require special well-completion methods to obtain economic flow rates. One striking feature that is common to unconventional reservoirs is the unusual fluid distribution. Conventional reservoirs typically exhibit lower density fluids overlying higher density fluids (Figure 1a), but fluid distribution can be unpredictable in unconventional reservoirs (Figure 1b). Fine-grained mixtures of silicate and carbonate minerals and organic matter generate complexities in pore systems and petrophysical properties (e.g., pore size, pore-throat size and wettability). Controls exerted by fluid properties and petrophysical properties on fluid distribution are poorly understood; consequently, saturation and flow rates are difficult to predict with confidence in unconventional reservoirs simply based on position within a geological structure. Therefore, it is critical to develop reliable petrophysical models to predict fluid distribution, improve productivity and reduce risks associated with the exploitation of unconventional plays.

Some oil and gas fields of the Montney Formation, in northeastern British Columbia (BC), present unusual fluid distributions, with gas pools either overlain by water-saturated layers (Wood, 2013) or, the major focus of this study, with 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.

The Montney Formation is one of the most important plays in North America (Seifert et al., 2015; Proverbs et al., 2018), hosting the most important unconventional reservoirs of the Western Canada Sedimentary Basin (Owen et al., 2020), as well as one of the most important siltstone reservoirs in the world (Vaisblat, 2020), with estimated reserves of 12 719 billion m^3 (449 tcf) of gas, 2308 million m^3 (14 521 mmbbl) of natural-gas liquids and 179 million m^3 (1125 mmbbl) of oil (National Energy Board et al., 2013). The migration of hydrocarbons into and out of the reservoirs is simulated for a dataset from the Septimus field of the Montney Formation; located in the overpressured part of the Montney play, the Septimus field is characterized by the accumulations of oil updip of gas (Figure 1b).

Hydrocarbon Migration and Capillary Pressure

When two immiscible fluids like water and oil or gas are present in the same pore, interfacial tensions exist at the interface between the two fluids. The pressure difference at this interface describes the capillary pressure (Schowalter, 1979). The capillary pressure P_c is given by the following equation:

$$P_c = \frac{2\sigma \cos\theta}{r} \qquad (1)$$

where σ is the interfacial tension, θ the contact angle, and r the pore-throat radius. An inverse relationship exists between capillary pressure and pore-throat radius. Therefore, capillary pressure is also directly related to the rock fabric and its petrophysical properties. During hydrocarbon migration, buoyancy is the driving or upward-directed force and is resisted by capillary forces (Figure 2; Schowalter, 1979; Carruthers, 2003), resulting in capillary pressure being one of the main constraints to oil migration (Carruthers and Ringrose, 1998; Carruthers, 2003). For hydrocarbon migration to occur, the buoyancy forces need to exceed the capillary forces (Carruthers, 2003).

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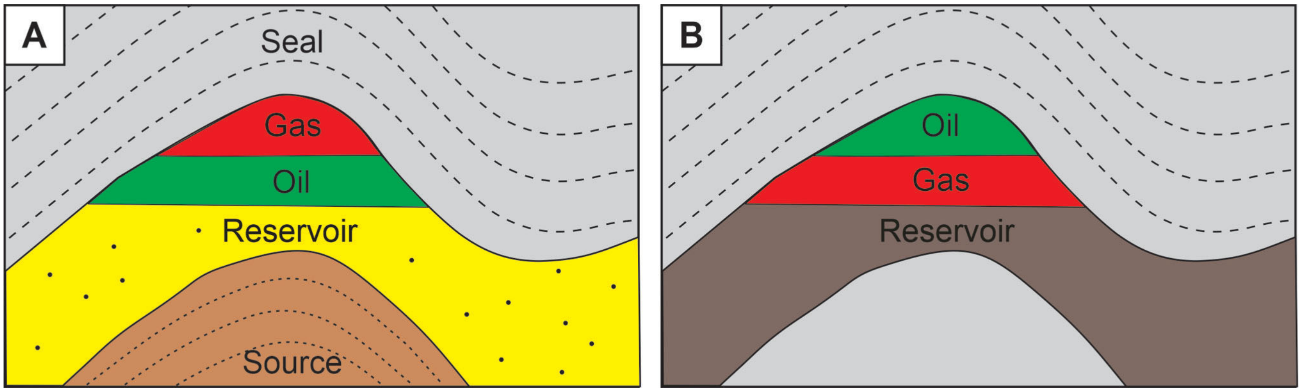

Figure 1. Fluid distribution in **a)** a conventional reservoir, with gas overlying oil, and **b)** an unconventional reservoir, with higher density fluids overlying lower density fluids, as seen in the Montney Formation of northeastern British Columbia.

Geological Setting

The Lower Triassic Montney Formation forms a west-dipping clastic wedge deposited on the northwestern margin of the supercontinent Pangea (Proverbs et al., 2018; Zonneveld and Moslow, 2018; Vaisblat 2020). The formation covers an area of 130 000 km^2 in southwestern Alberta and northeastern BC (Figure 3; Vaisblat, 2020); it can reach a thickness of up to 350 m in 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; Owen et al, 2020). The formation was deposited on a shallow clastic ramp in an arid coastal-margin setting, with ephemeral rivers and deltas contributing to the main sediment influx (Proverbs et al., 2018; Zonneveld and Moslow, 2018). Depositional environments range from shallow marine to submarine fans (Zonneveld and Moslow, 2018; Vaisblat, 2020). The Montney is subdivided into Lower (Griesbachian–Dienerian), Middle (Smithian) and Upper (Spathian) members (Zonneveld and Moslow, 2018).

Dataset

Gamma-ray, neutron porosity and density logs from 15 wells of the Septimus field (Figure 4) were used to conduct a probabilistic cluster analysis with the GAMLS (Geologic Analysis via Maximum Likelihood System) software (Eslinger and Everett, 2012) to identify four modes (or electrofacies) 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 its distinct and different mineralogical composition, organic carbon content, rock fabric and petrophysical properties that include pore-throat size and capillarity entry pressure.

Methods

The petrophysical and fluid properties are both accounted for in the modelling of hydrocarbon migration. Modelling

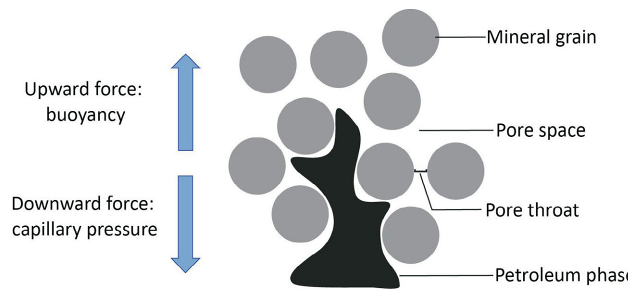

Figure 2. Illustration of opposing forces involved during the migration of hydrocarbons; this example depicts a water-wet rock.

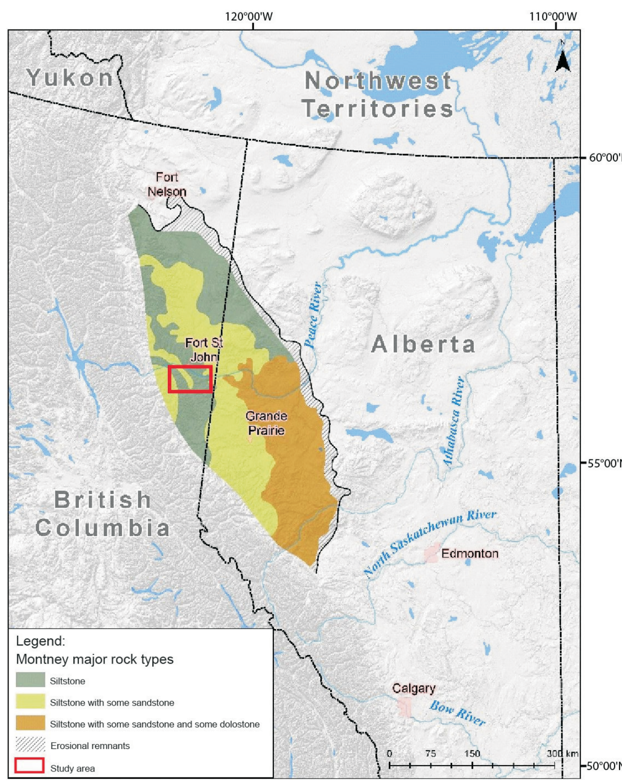

Figure 3. Geology of the Montney Formation, northeastern British Columbia (after National Energy Board et al., 2013). The location of the study area is outlined in red.

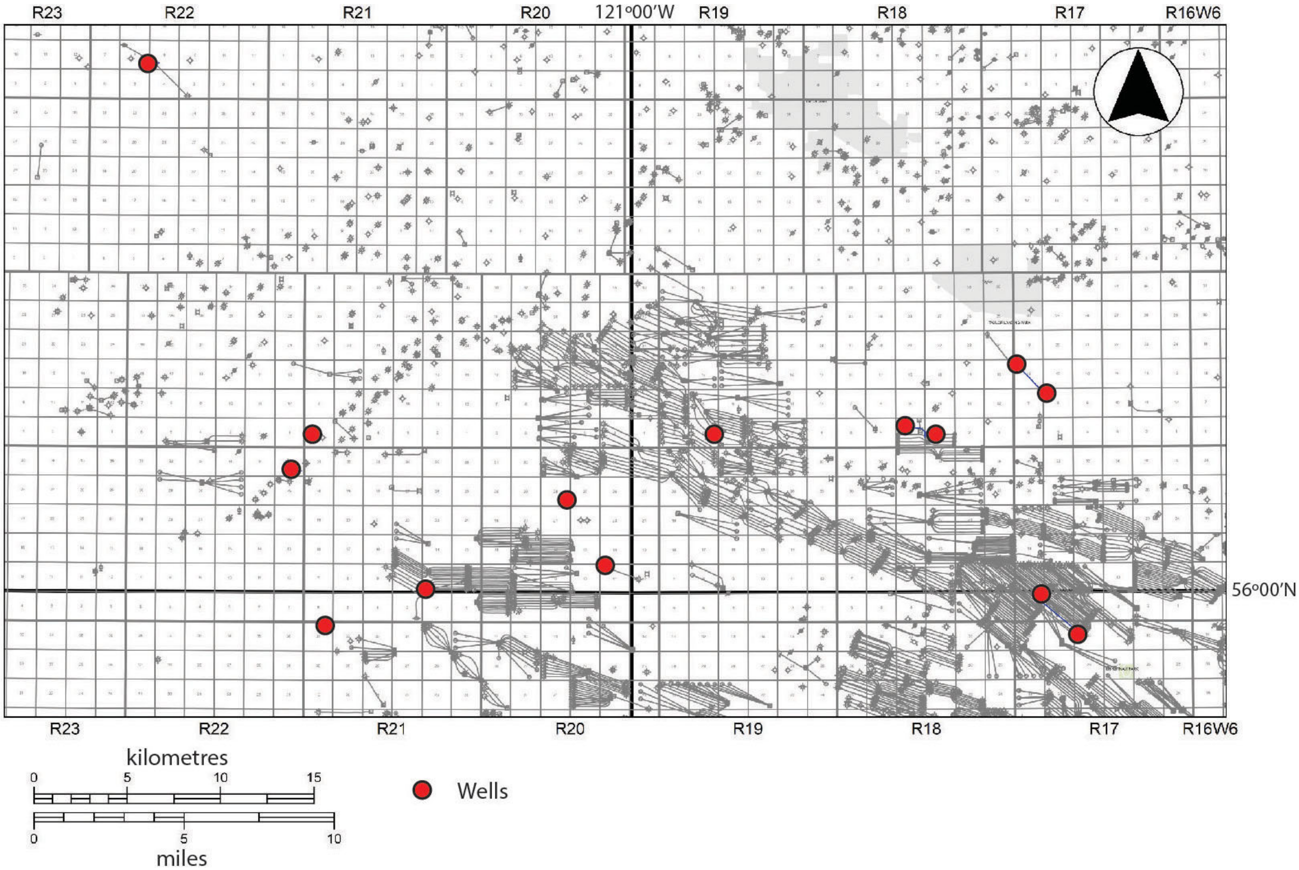

Figure 4. Septimus field of the Montney Formation, northeastern British Columbia, and location of the wells used in this study.

is accomplished using Permedia® software, a petroleum-system modelling toolkit developed by Halliburton 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. The advantages of invasion-percolation theory are its low computational demand and the capability of representing small-scale heterogeneities in the reservoir (Trevisan et al., 2017).

Current Research Directions

A suite of flow simulations to test the role of petrophysical and fluid properties in controlling fluid distributions in the Septimus field is being developed, applying petrophysical data acquired by Hernandez et al. (2020) in a spatial array that mimics the Septimus-field structure.

Hernandez et al. (2020) determined specific capillary entry pressure for each of four selected rock types. In this study, only two of those rock types were used in the initial models: the ones with the lowest and highest capillary entry pressures. Using the same wells as in Hernandez et al. (2020), a reservoir mesh (Figure 5) was created incorporating only these two end-member rock types.

In model 1 (Figure 5a), the reservoir is composed of one layer consisting of two different rock types: the deepest part of the reservoir has a lower capillary entry pressure compared to the shallowest part of the reservoir. In model 2 (Figure 5b), the deepest part of the reservoir is composed of the rock type with the low capillary entry pressure, whereas the shallowest part of the reservoir consists of a layer of that same rock type with low capillary entry pressure overlain and underlain by the other rock type with a higher capillary entry pressure.

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 on the fluid distribution. The simulation with oil is expected to invade both rock types (Figure 5c, d), based on the relatively low interfacial tension between oil and water (Schowalter, 1979). However, the interfacial tension between gas and water is higher and, as a result, the displacement pressure for water-gas is greater than the one for water-oil (Equation 1). This means that for the same rock type, a higher displacement pressure will be required for gas to enter compared to that required for oil. After injection of gas, a segregation of the fluids is expected, with gas entering only the rock type of low capillary pressure (Figure 5e, f).

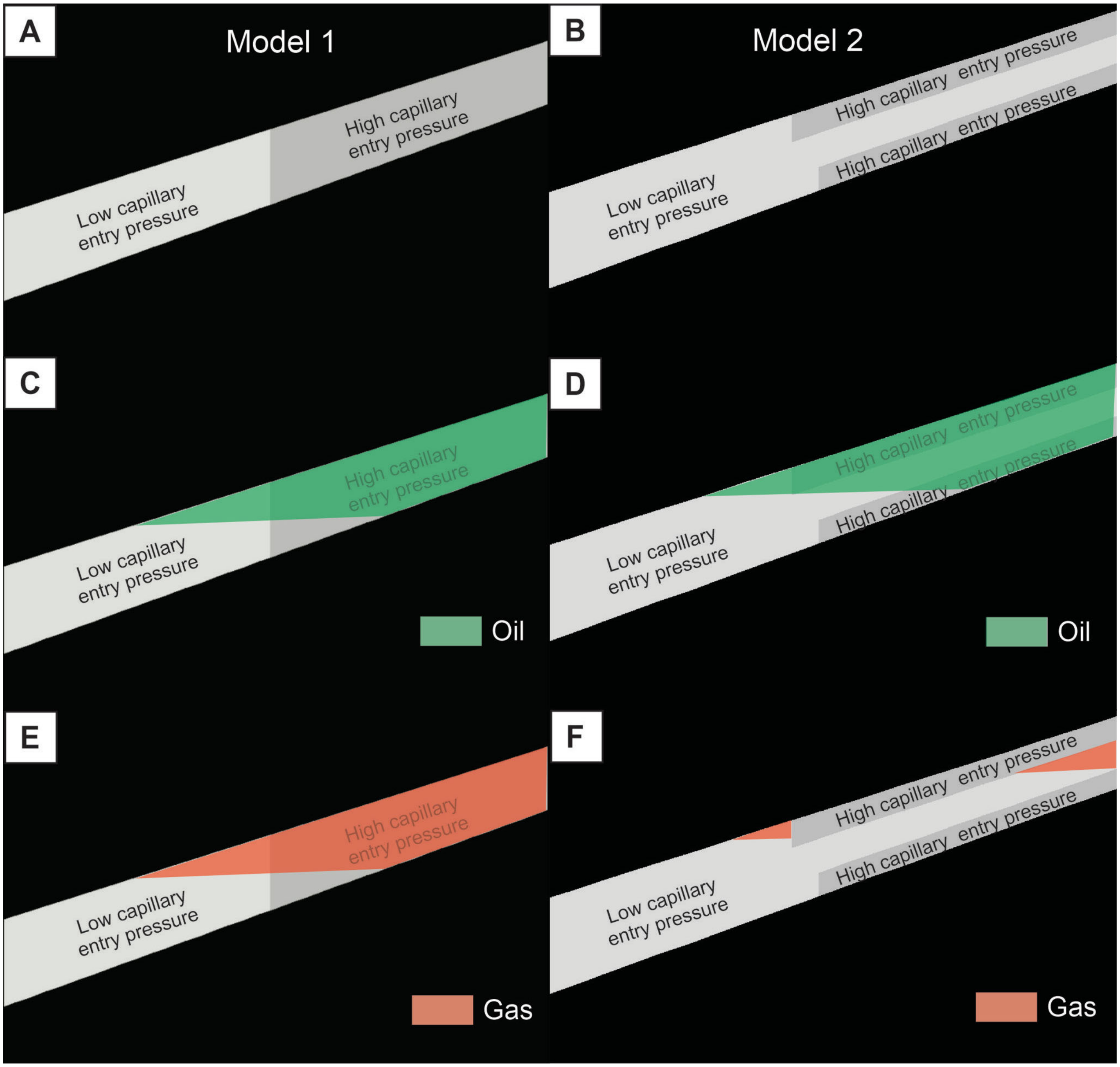

Figure 5. Models 1 and 2 of reservoirs showing in **a, b)** low and high capillary-entry–pressure rocks; **c, d)** after the injection of oil into the reservoir, oil is expected to enter both rock types; and **e, f)** after the injection of gas, only the rock type of low capillary-entry pressure is expected to be filled with gas.

Once the initial set of models is tested and results confirm that rock facies and capillary pressure control segregation of the fluids in the reservoir, new simulations will be run, integrating more wells to extend the reservoir mesh to field scale. 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.

Conclusions

The project, in an early phase of development, will apply a combination of field data, petrophysical data and numerical modelling to develop constraints on factors controlling fluid segregation in the Montney Formation.

This project will lead to the development of new models for hydrocarbon migration and distribution in unconventional reservoirs. This work is potentially of great economic significance; these models could help in predicting the type of hydrocarbons present in unconventional plays, as well as saturation values and producibility within unconventional petroleum systems and, therefore, could contribute to reducing the risks and costs associated with the exploitation of these resources. The insights gained on this project may be useful not only for the Montney Formation but also for other reservoirs, such as the Lower Cretaceous sandstones in the Deep Basin of the Western Canada Sedimentary Basin or the Upper Cretaceous Rocky Mountain tight-gas-sand accumulations in the United States.

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