Application of Migration Modeling to Unconventional Reservoirs: An Example from the Montney Formation, Northeastern British Columbia, Canada

Victoria Chevrot[1], Nicholas B. Harris[1], Stephany Hernandez Medina[1], Noga Vaisblat[1]
[1]Univeristy of Alberta

Summary

In unconventional reservoirs, models for fluid distribution are critical to appraising resources and planning developments but are poorly understood. We propose that petrophysical properties of reservoir rocks combine with fluid properties to determine hydrocarbon migration in low porosity systems with small pores. These controls are evaluated through numerical simulations of reservoir filling.

During migration, two main forces are present: buoyancy and capillary pressure. The fluid properties affect the capillary pressure, with interfacial tension being positively related to capillary pressure. Fluid compositions govern the buoyancy force, where lower density fluids are more buoyant. Rock properties also impact the capillary pressure, a rock with smaller pore throat will have a higher capillary pressure, the rock wettability also affects the capillary pressure.

We test models for fluid distribution in an unconventional reservoir by simulating the migration of the hydrocarbons in the Montney Formation reservoir at Septimus field in northeast British Columbia where oil is present up-dip of gas. By injecting different fluid compositions in the model, and applying different capillary pressures to the rocks, we can look at the relationships between fluid composition, capillary pressure, and fluid distribution and test reservoir charging scenarios. Because fluid properties vary with pressure and temperature, we also examine reservoir charging at different depths and under different geothermal gradients to understand how this affects migration in an unconventional reservoir like the Montney Formation.

Introduction

The Lower Triassic Montney Formation of the Western Canadian Sedimentary Basin is one of the most important plays of North America (Seifert et al., 2015; Proverbs et al., 2018), 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 is dominated by dolomitic siltstone, with local very fined-grained sandstones (Zonneveld and Moslow, 2018; Vaisblat et al., 2021). In some fields, the Montney Formation presents gas pools overlaid by water-saturated layers (Woods, 2013) and gas pools overlaid by oil pools, which is the case in the Septimus field (Hernandez, 2021), the focus of this study case. Hernandez (2021) identified 4 rock types in the reservoir section. Each rock type is characterized by distinct and different mineralogical composition, organic carbon content, rock fabric, and petrophysical properties that include pore throat size and capillarity entry pressure. Moreover, samples from the oil well and gas well present significant differences in petrophysics for a same rock type. Our interpretation is that the rock properties are related to the presence of an original oil column, and that the rock properties control which fluid type enter the reservoir via buoyancy.

Background on hydrocarbon migration

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). For hydrocarbon migration to occur, the buoyancy forces need to exceed the capillary forces (Carruthers, 2003). When two immiscible fluids like water and oil or gas are present in the same pore, interfacial tension exists 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:

$$P_c = \frac{2\sigma coscos\,\theta}{r} \quad (1)$$

Where σ is the interfacial tension (IFT), θ the contact angle, and r the pore throat radius. An inverse relationship exists between capillary pressure and pore throat radius. Therefore, it is also directly related to the rock fabric (grain size, pore and pore throat size) and the composition of the material lining the pore walls.

Approach

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, instead of by fluid density. We test this model at Septimus field, an oil and gas accumulation in British Columbia in the Montney play in which a distinctive segregation of hydrocarbon types is observed where oil overlies gas. Initial conceptual models are used to investigate the relationship between the fluid distribution and the two variables capillary pressure and fluid composition. Modeling is accomplished with the software Permedia®, a petroleum system modeling toolkit 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 petrophysical and fluid properties are both accounted for in the modeling of hydrocarbon migration. To obtain the fluid properties (density and IFT), we use the Winprop® module form the Computer Modelling Group® software package. Winprop® is a fluid properties characterization tool.

Results

A simple reservoir mesh is created with rock properties based on two of Hernandez's (2021) rock types (Figure 1). The reservoir is composed of one layer consisting of two different rock types: the deepest part of the reservoir has a set value of low capillary entry pressure while the shallowest part of the reservoir has a higher capillary pressure that is varied between experiments. Fluids are injected at the deepest point in the reservoir, and the fluids migrate through the low capillary pressure rock and into the high capillary pressure rock.

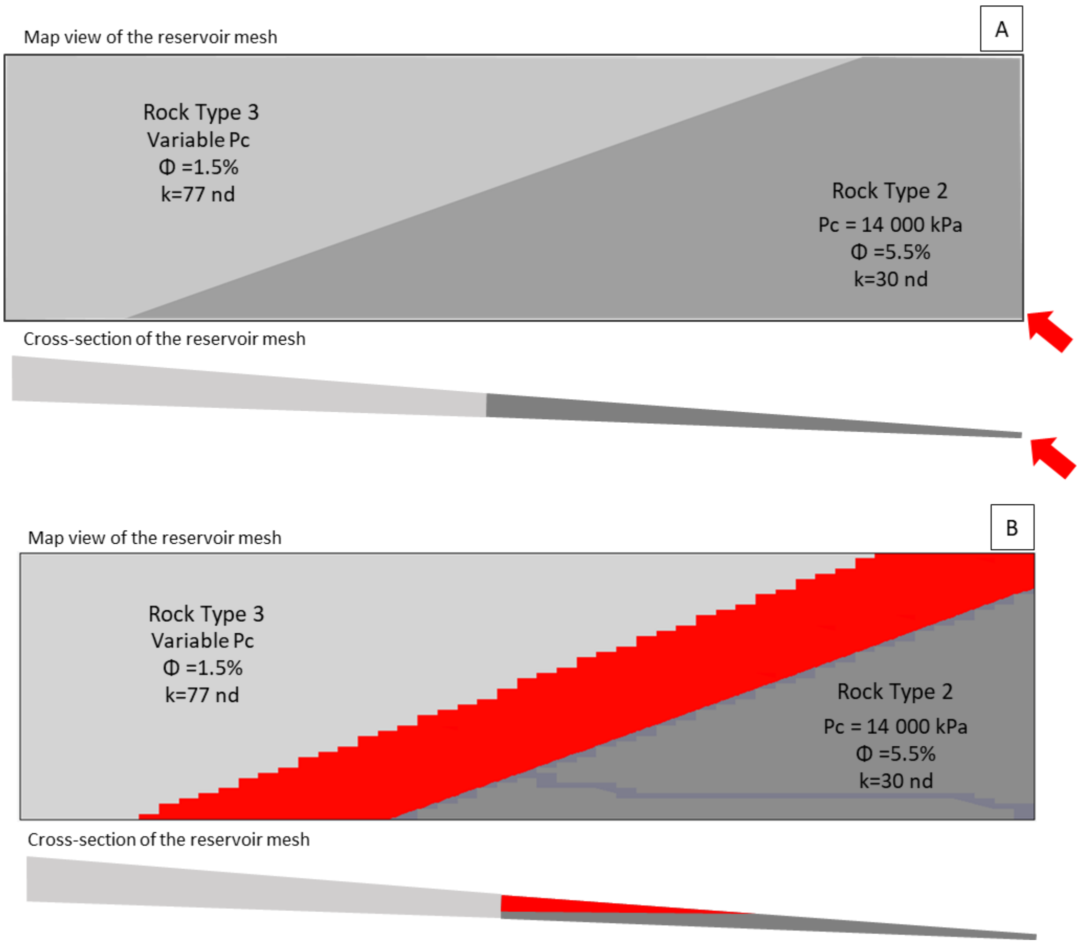

Figure 1: (A) Map view and cross-section (vertical exaggeration x5) of the reservoir mesh with the two different rock types. The rock type 2 in the deepest part of the reservoir has a capillary pressure set at 14,000 kPa. The red arrows indicate the injection point. (B) Example with gas accumulation below the seal formed by the rock type 3.

The depth of the reservoir at the time of hydrocarbon charging has a direct impact on the fluid properties, because density and IFT both depend on pressure and temperature (Schowalter, 1979). The first series of models was run with pure methane gas migrating into a water-saturated reservoir. Different reservoirs depths at the time of charging were tested ranging from 2000 to 5000 m, assuming a normal pressure gradient of 9.79 kPa/m and two geothermal gradients of 25 and 40°C/km.

The density of methane increases with increasing depth (Figure 2A) and ranges between 70 kg/m^3 at 1000m deep and 212 kg/m^3, while IFT between methane and pure water decreases with increasing depth (Figure 2B).

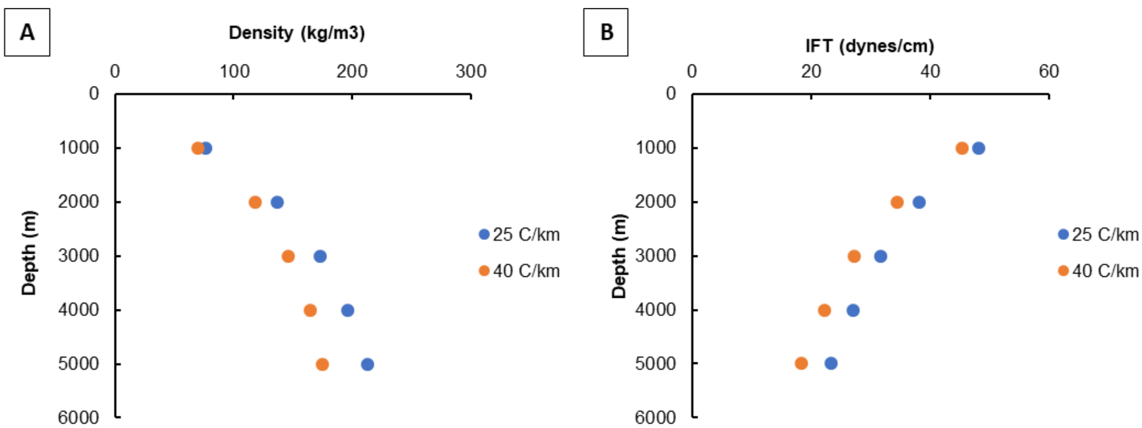

Figure 2: Density (A) of methane and IFT for pure water and methane (B) as a function of depth with geothermal gradients of 25 and 40°C/km.

Several simulations were run, increasing the capillary pressure in the shallow part of the reservoir, until a seal forms and the fluid cannot enter the high capillary pressure rock anymore. By using equation (1), we can relate that capillary pressure to pore throat size and define the smallest pore throat size that each fluid can enter. The results are presented on Figure 3. At depths greater than 3000m, methane can enter progressively smaller pore throats with increasing reservoir depth, a result of reduced IFT with depth and increasing temperatures (Figure 1B). At 2000m depth, despite higher IFT, the low density of methane allows the fluid to enter smaller pore throats. Methane density is lower with a geothermal gradient of 40°C/km than with a gradient of 25°C/km, allowing methane to enter even smaller pore throat at higher temperatures.

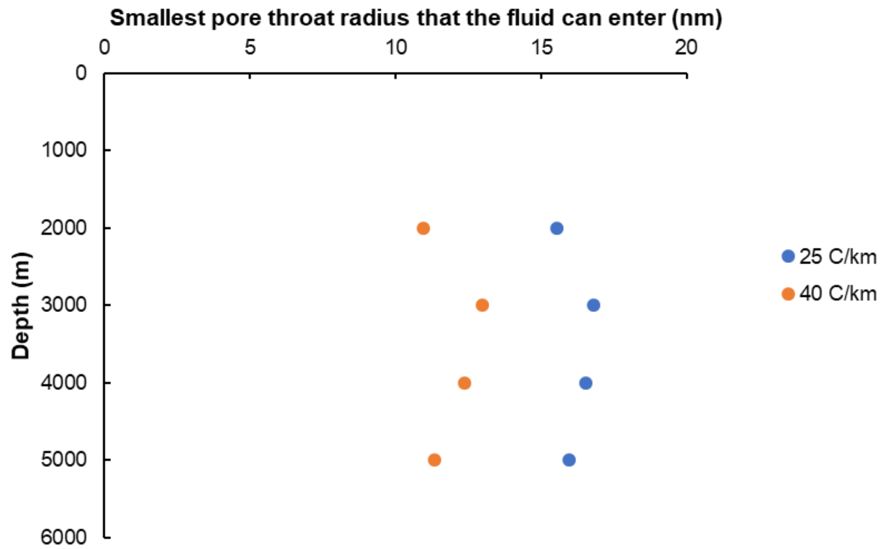

Figure 3: Smallest pore throat (nm) that pure CH_4 can enter during migration in a water-saturated reservoir at different depths, with two geothermal gradients.

Future Work

The next models will examine different fluid compositions. Fluids with a carbon number equal or greater than 3 have densities that decrease with depth, contrary to the behavior of methane, which should change the relationship between depth and the pore throat size that the fluid can enter.

The models presented here were run under normal pressure gradient and with pure water in the reservoir. Additional research will focus on the effect of the brine salinity, to investigate its impact on IFT and how this reflects on the fluid migration. Another series of models will be run to examine the effect of overpressure on the fluid migration.

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