Pore-scale variability and fluid distributions in Montney Formation: New insights from three-dimensional reservoir characterization and modeling

Sochi C. Iwuoha, Per K. Pedersen, and Christopher R. Clarkson
Tight Oil Consortium, Department of Geoscience, University of Calgary, Alberta, Canada

Summary

In the Triassic Montney Montney Formation in Alberta and British Columbia (Fig. 1 and 2), different fluids are produced (oil, gas condensate, dry gas). This study focuses on a Montney producing area in west central Alberta (Fig. 1) where thermal maturity and depth data are inconsistent with the production of different fluids. This evaluation reviews the potential control of pore size on fluid distributions in the study area. Our workflow utilizes well logs, core data and three-dimensional (3D) geological modeling techniques to map facies, petrophysical properties and pore size distribution in the study area. Our results show that gas and condensate producing areas have mean dominant pore throat sizes of 20 - 30nm with a wider range of pore size distribution (up to 55nm) occurring in the condensate producing area. The mainly oil producing area shows a lower mean dominant pore size of 10 - 20nm with a marked increase in siltstone and shale heterolithics eastwards. Although porosities in the oil trend are relatively higher (mean ~4.5%) than those within the gas and condensate producing areas (mean ~3% and 4% respectively), permeabilities are lower in the oil trend (mean 0.27×10⁻¹⁰ m²) compared to the gas (0.32×10⁻¹⁰ m²) and condensate (0.48×10⁻¹⁰ m²) producing areas. The relatively larger pores in the gas and condensate producing areas which appear to control permeability may have facilitated secondary migration of lighter hydrocarbons into the gas and condensate producing areas, leaving the oil in the eastern more heterogenous size-limited pores in the oil area unswept. Our finding supports the thermal maturity data in the study area from rock-eval pyrolysis (interpreted as oil window) and the hypothesis of potential secondary gas migration in Montney Formation literature. The data integration and 3D geological modeling approach that lead to our findings are the focus of this paper.

Introduction

Given the decline in commodity prices over the last few years, research into understanding the reasons for the occurrence of different types of...
hydrocarbon fluids in the Triassic Montney Formation is gaining an audience. Previous workers have proposed different mechanisms beyond the control of thermal maturity and depth, such as secondary migration and leakage of methane (Wood and Sanei, 2016). Whereas the existing body of knowledge suggests explanations for the variation in fluid distribution in Montney Formation using data such as fluid compositions (Wood and Sanei, 2017), these studies generally address lateral variations in fluid types with less detail provided on the vertical controls. In this study, we utilize 3D geological modeling as a medium for multi-source, multi-scale data integration to evaluate both lateral and vertical controls on fluid distribution in the formation.

We focus on evaluating pore size variation and its influence on fluid distributions (lean gas, wet gas, and oil) observed in Montney Formation within a 12 townships (1, 105 km², ~ 427 sq. miles) area in west central Alberta (Fig. 3). The study area context, general reservoir and production characteristics are presented below:

**Depositional setting:** Shallow shelf

**Reservoir depth:** 1700m – 2500m MSL

**Reservoir temp:** 59 - 67 degC

**Initial pressure:** 30 – 40 MPa

**Porosity (\( \Phi \)):** 1 – 7% (Avg. 4%)

**Permeability (\( K_a \)):** 0.00001 < \( K < 0.01 \) mD

\( \frac{K_y}{K_a} : 0.01 – 0.67 \)

**Main hydrocarbon fluid types:**
- Lean gas
- Rich gas
- Oil

**Gas Production:** 2 – 28 MMscf/d

**Liquid gas ratio:** 50 – 250 bbls/MMscf

**Upper Montney**

### Data Analysis and Method

Data from 392 Montney producers (Fig. 3) show lean gas production in the west-northern portion of the study area (termed the Lean Gas Trend – LGT). The central to north-central area is dominated by a wet gas trend with elevated levels of condensate production of up to 250 bbls/MMscf (termed the Wet Gas Trend – WGT). Mainly oil production occurs in eastern – northeastern portions of the study area (termed the Oil Trend – OT).

Fig. 3. Bubble map of first 36 months production in the study area. Note that the solid lines of the fluid type boundaries (also shown in Fig. 4) do not connote geologic limits.

The Montney Formation top of structure map was created using corrected and correlated formation tops from 88 vertical wells (red colored wells in Fig. 4). The resulting map (bottom-right map in Fig. 6) was
quality controlled using the Montney Formation tops from the 392 Montney producing wells. Facies were defined using a gamma ray (GR) criteria to capture lithologies in Montney Formation in the study area; being siltstones, sands, and shales (Fig. 1, 5 and 6). The GR facies criteria was checked for lithology consistency using overlying well known Cretaceous and Jurassic units that contain siltstones, sands, and shales such as the Cardium, Kaskapau, Dunvegan, Fahler, and Fernie. The core porosity (Phi) and permeability (K) were obtained from depth-corrected core data in five wells with cores cut in the LGT, WGT, and OT (Fig. 4 and 5). Log Phi was computed from the bulk density log. Log K was calculated using log Phi and the relationship between log Phi and slip and in-situ stress corrected K obtained from core analysis (pulse-decay and probe profile K measurements) on a well in the study area (well X, shown in Fig. 7). Core K was also slip and in-situ stress corrected using the same relationship.

Fig. 4. Bubble map of first 36 months production in the study area. The 5 cored wells (light green circles) are sequentially numbered from west to east as CW1 to CW5. The naming system for the vertical wells (blue circles is explained in Fig. 6)

A 3D grid was constructed with 75m x 75m x 2m cell size, oriented 45° east (consistent with the maximum horizontal stress direction), including 50 geological layers in the ~100 m thick Upper Montney interval). For completeness (although not the focus of our evaluation), 10 layers (~10m thick) were included in the ~
100m thick Lower Montney interval. The 3D facies model was constructed by distributing upscaled facies (using the “most-of” algorithm) in the 3D grid through sequential indicator simulation (SIS). Upscaled log Phi (arithmetic method) and K (geometric method) were distributed in 3D using sequential gaussian simulation (SGS). K was co-kriged with Phi using a correlation coefficient of 0.56 obtained from a cross plot of log Phi and slip and in-situ-corrected probe K in well X within the study area (well X is discussed in Clarkson et al. (2016) and shown in Fig. 7). A northwest-southeast (NW-SE) oriented 6.4km x 6.4km (“major” x “minor” direction) model dimension-dependent spherical variogram that is consistent with the shelf to basinward regional direction of facies change in the formation was used for both facies and petrophysical modeling, with a vertical range of 3m in the Upper Montney interval. The resulting properties were quality-controlled with core data in the five cored wells. A crossplot of core Phi with slip and in-situ stress-corrected K were created and the modified Winland correlation documented in Di and Jensen (2015) was used to identify the pore throat sizes for each of the core samples in the Upper Montney interval in the LGT, WGT, and OT. Lastly, we utilized the Phi-K model, fluid composition data and formation breakdown pressures in well Hz1 (a northwest oriented 2km long lateral whose surface location is shown in the Montney top of structure map in Fig. 6) to investigate the pore size control on vertical variations in fluid composition in this horizontal well. Fluid composition data acquisition from cuttings samples and isoforms in Hz1 is discussed in Clarkson et al. (2016)

**Results**

In the study area, Siltstones (67%) and shales (31%) dominate the Upper Montney interval, which is the focus of our evaluation (Fig. 6). We suspect the occurrence of structural lineaments (likely linked to underlying Leduc reef margins) in the study area based on structural deformations that are apparent in the Montney top structure map (bottom-right map in Fig. 6). A crosscheck of the facies model through the geological layers in the model did not highlight a potential control of the lineaments on facies distribution. Further investigation of the potential influence of these structures on fluid distribution is beyond the scope of our evaluation at this time.

**Fig. 6.** Structural cross-section, facies modeling result and Montney top structure map showing the transect of the cross-section. Note that the 23 wells in the cross-section are comprised of vertical wells (W1 to W18 named sequentially along the transect from A to B) and the cored wells CW1 to CW5. The log shown in the wells is GR (doubled track). Additional formation tops in wells close to the transect that were used for structural calibration are shown in the WGT (sky blue circles). CW1 (in the LGT) and CW3 (in the WGT) are cored and sampled across in Upper Montney at similar depths thus partly precluding a depth control on fluid distributions.
Results of the cross plot of Phi-K data from the cored wells and well X with Winland correlation lines for dominant pore throat size identification are shown in Fig. 7.

**Fig. 7.** Core Phi and slip, stress-corrected K, with Winland correlation for dominant pore throat size identification

We investigated the facies control on Phi-K by coloring the Phi-K crossplot with facies (Fig. 8). In Fig. 9, we show the Phi-K variation for each of the fluid type areas. From both Fig. 8 and 9, it can be seen that the higher porosity (>5%) shale samples occur in the OT. However, higher porosities in these shales do not always correspond to higher permeabilities.

**Fig. 8.** Core Phi and slip, stress-corrected K, colored by facies (well X is excluded)

**Discussion and Conclusions**

Based on the data evaluated in the study area, porosities in the oil trend are relatively higher (mean of all samples ~4.5%) than those within the gas and condensate producing areas (mean ~3% and 4% respectively). Permeabilities are lower in the oil trend (mean ~0.27µD) compared to the gas (mean ~0.32µD) and condensate (mean ~0.48µD) producing areas (Fig. 9). Relatively larger pores occur within the gas and condensate producing areas (Fig. 10). Given the non-linear Phi-K relationship(s) in the samples studied (Fig. 7, 8, and 9), it does appear that within the study area the variation in pores sizes and the closer relationship between pore sizes and permeability proffers a plausible explanation for the variation in fluid types (Fig. 9 and 10). In one hand, larger pores correlate more with higher permeability (seen in CW1, CW2, and CW3 which are in the LGT and WGT). On the other hand, smaller pore sizes in CW3 and CW4 correlate with lower K in the OT. (Fig. 9 and 10). Note that the increased shale content in the OT will likely accentuate the restrictions in the pore space in this area. The thermal maturity data from rock-eval pyrolysis in the study area suggests an oil window maturity. This could imply that lighter hydrocarbons may have migrated into the study area with the displacement of oil only possible in the LGT and WGT where the overall higher K, controlled by pores sizes allowed fluid influx. Although we would
expect gas to be able to permeate the smaller pore spaces found in the OT, it appears that the increased shale content and potentially more complicated pore system may have mitigated this occurrence. Comparatively, in the LGT and WGT, the smaller pores and lower K in the LGT appears to be more favorable to lean gas influx which is more in line with expectations.

**Fig. 9.** Siltstone and shale Phi - K in the LGT (CW1), WGT (CW2 and CW3), and OT (CW4 and CW5). Note that the OT has a higher proportion of shales (see Fig. 5 and 6). The higher proportion of shales in the OT will likely play a role in controlling fluid storage and transport behavior in the eastern portion of the study area (also see Fig. 5 and 6). Shales in CW2 were sampled, however, both have a K of 1.1µD.

**Fig. 10.** Siltstone and shale pore sizes in the LGT (CW1), WGT (CW2 and CW3), and OT (CW4 and CW5). Note that the OT has a higher proportion of shales (see Fig. 5 and 6), hence the tendency to have smaller (likely more complex) pore system.

Our evaluation of Hz1 (located in the WGT) vertical variation in C1/C2 gas ratios revealed results that are consistent with our findings in the vertical cored wells evaluated. Higher C1/C2 ratios correlated with pore sizes of >20nm while C1/C2 ratios decreased when pore sizes were ≤20nm (**Fig. 11**). Breakdown pressure data from the hydraulic fracture stages (track 3 from the left in **Fig. 10** well log panel) captures the variation...
in internal rock (likely linked to pore) fabric and corroborates the pore scale variations captured at 3D grid scale by variations in the Phi-K model.

**Fig. 10.** Phi-K model in Hz1 showing the correspondence of larger pore sizes with higher C1/C2 ratios (spikes in track 6) in the well log panel on the right.

In closing, our findings from this research highlight that dominant pore throat sizes exhibit some control on lateral fluid distribution and vertical variations in composition in each of the fluid type areas studied. The LGT and WGT likely contain migrated hydrocarbons while the OT appears to be unaffected by secondary gas migration due to a likely more complex pore system. Our pore size estimations are consistent with pore size ranges in published literature for the Montney Formation within the study area, as well as estimates from rate of adsorption measurements performed in cores in the study area.

To the best of our knowledge, this study represents the first attempt at utilizing a 3D geological model framework coupled with modified Winland correlations to assess lateral and vertical relationships between pore sizes and fluid distributions in Montney Formation, west-central Alberta. Further evaluation of pore size controls on fluid distribution in other non-cored vertical as well as horizontal wells would be the focus of a future evaluation.

**Acknowledgments**

Sochi would like to thank co-authors Dr. Per K. Pedersen and Dr. Christopher R. Clarkson. We are grateful to sponsors, staff, and colleagues at the Tight Oil Consortium (TOC) at the University of Calgary. Staff and colleagues at the Centre for Applied Basin Studies (CABS), University of Calgary are recognized for their camaraderie and helpful comments. We acknowledge the continued support of Geologic Systems, and Schlumberger through their software donations to the University of Calgary. This research was partially funded by the NSERC-CRD grant.

**Bibliography**


