GeoConvention 2015
GEOSCIENCE
new horizons
Telus Convention Centre • 4-8 May 2015 • Calgary, AB Canada

Geological Controls on Reservoir Properties of the Montney Formation in Northeastern BC: An integration of sequence stratigraphy, organic geochemistry, quantitative mineralogy and petrophysical analysis.

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Introduction

The Montney-Doig petroleum system is the largest known unconventional play in Canada and the host of huge volumes of hydrocarbons in Western Alberta and Northeastern British Columbia. Thanks to horizontal drilling and multistage hydraulic fracturing, the resource production started ramping up in 2006 and has been growing exponentially since then. During the last decade, economic optimization of the development has been largely driven by stimulation design experimentations, increasing the lateral length, the number of fracturing stages and fluid volumes, while focusing on liquid-rich areas of the system. Although all these factors are, and will stay key elements of success, a better understanding of the geological controls on productivity will assume more importance in future development. In Northeastern BC, the Montney formation is typically 200 to 400 m-thick and predicting how reservoir and fluid properties vary throughout this interval will give an edge to companies for landing horizontal wells and designing appropriate stimulation treatments.

This study aims at better understanding the controls on vertical heterogeneities in a 360 m-thick Montney to Doig Phosphate interval and how these heterogeneities affect the reservoir properties and fluid saturations, based on an extensive data set from a well located in the Norhern Montney field.

Context of the study

In self-source reservoirs, hydrocarbons tend to be diffuse in thick intervals of very fine-grained rocks with very low porosity and permeability. The concentration and maturity of organic matter in these sediments is the main control on the generation of hydrocarbons, part of which stay in the source rock, is forced into adjacent tight reservoir or migrates over long distances to form conventional plays.

Due to the very poor reservoir quality of source-rocks and associated organic-lean tight reservoirs, an effective extraction of this resource requires horizontal drilling and multistage hydraulic fracturing. The success of reservoir stimulation is strongly influenced by reservoir mechanical properties which are directly related to the mineralogy of the matrix and the rock fabric (natural fractures, bedding, etc.). Small-scale reservoir heterogeneities like bioturbation also influence the pore connectivity and fluid saturations (Wood, 2012). In the Montney Formation of Northeastern BC, all these parameters vary at high frequency over a several hundred metres of series and understanding these variations is key to optimizing the landing of horizontal wells and the stimulation design.

In this study, we investigate the geological controls on reservoir property variations over a 360 m-thick interval from the base of the Montney to the top of the Doig Phosphate. Our interpretation is supported by a well-defined stratigraphic architecture at basin scale (Crombez et al, 2014) and based on the integrated analysis of an extensive dataset from a well in the Northern Montney field. This dataset includes routine core analysis from 3 cores, QEMSCAN quantitative mineralogical data and Rock-Eval analysis from 98 cutting samples, as well as an extensive suite of well logs including Nuclear Magnegtic Resonance and Nuclear Spetroscopy. This dataset is complemented by the description of a 300 m-long core over the entire Montney to Doig Phosphate secion from an offset well.

First, we examine the sedimentological, mineralogical and organic content variations throughout the studied interval and their relationship with sequence stratigraphic surfaces and system tracts. This qualitative analysis clarifies the variations and vertical trends in reservoir heterogeneity and their geological controls.

Second, we perform a petrophysical analysis integrating conventional and advanced logs with core and cuttings data. This quantitative analysis provides an insight on how reservoir heterogeneity variations impact on reservoir properties including porosiy, permeability, brittleness and fluid saturations.

Ultimately, looking at the production data from various intervals of the Montney Formation in the study area will help better anticipate the potential impact of reservoir heterogeneity on well performance.

Geological controls on reservoir heterogeneity

Our interpretation is based on the observation of vertical variations of the mineralogy and total organic carbon (TOC) from 98 cutting samples of the studied well and their relationship with stratigraphic surfaces and system tracts. The quantitative mineralogy was measured by SGS-Canada with QEMSCAN that combines Backscattered Electrons Imaging and (BSE) with Energy Dispersive X-ray Spectroscopy (EDS). The TOC measurement was performed by Rock-Eval VI at IFP Energies nouvelles.

Fig. 1 displays the mineralogical and TOC variations along with the Gamma Ray curve (left track) and the sequence stratigraphic surfaces. The definition of the stratigraphic units and the position of the surfaces result from the reconstruction of large scale geometries based on a basinwide 2-D cross-section (Crombez et al 2014). The Montney Formation is composed of three third-order stratigraphic sequences and the Doig Phosphate corresponds to the lower part of a fourth third-order sequence. For each sequence, four stratigraphic surfaces were defined: the Sequence Boundary (SB), the Transgressive Surface (TS), the Maximum Flooding Surface (MFS) and the Basal Surface of Forced Regression (BSFR).

General tendencies can be observed throughout the Montney Formation (arrows on Fig. 1): the proportion of clay and pyrite are decreasing upward, whereas the amount of feldspars and the grain size are increasing upward (QEMSCAN feldspar grain size proxy). This is consistent with the interpretation of an overall prograding system with shallowing upward tendency and progressively more proximal sediment source and higher energy (more oxygenation). TOC shows a relatively stable background level at around 1.2%.

These general trends are punctuated by higher frequency variations associated with third-order stratigraphic surfaces and system tracts (Fig. 1). Sequence 1 has a high clay content compared to the overlying sequences and MFS1 is associated with peaks in clay, TOC and minor increase in phosphate. Sequence 2 shows a basin ward shift of facies associated with a shrap decrease of clay and increase of carbonates across SB2. The calcite maximum peak associated with SB2 is clearly associated with shell debris observed on the core from the offset well. At the base of Sequence 3, a higher order flooding event is evidenced by dark massive siltstone immediately above SB3 (observed on the offset well) with local maxima in TOC, pyrite and phosphate. MFS 3 is also associated with local maxima of pyrite and TOC. The lower part of the sequence 4 (up to MFS4) is characterized by a massive increase of phosphate (Doig Phosphate) associated with a rapid increasing of TOC and carbonate content. On the offset well this interval shows abundant wave ripples, bioturbations, shell debris, phosphate grains as well as calcite and dark horizontal and vertical veins.

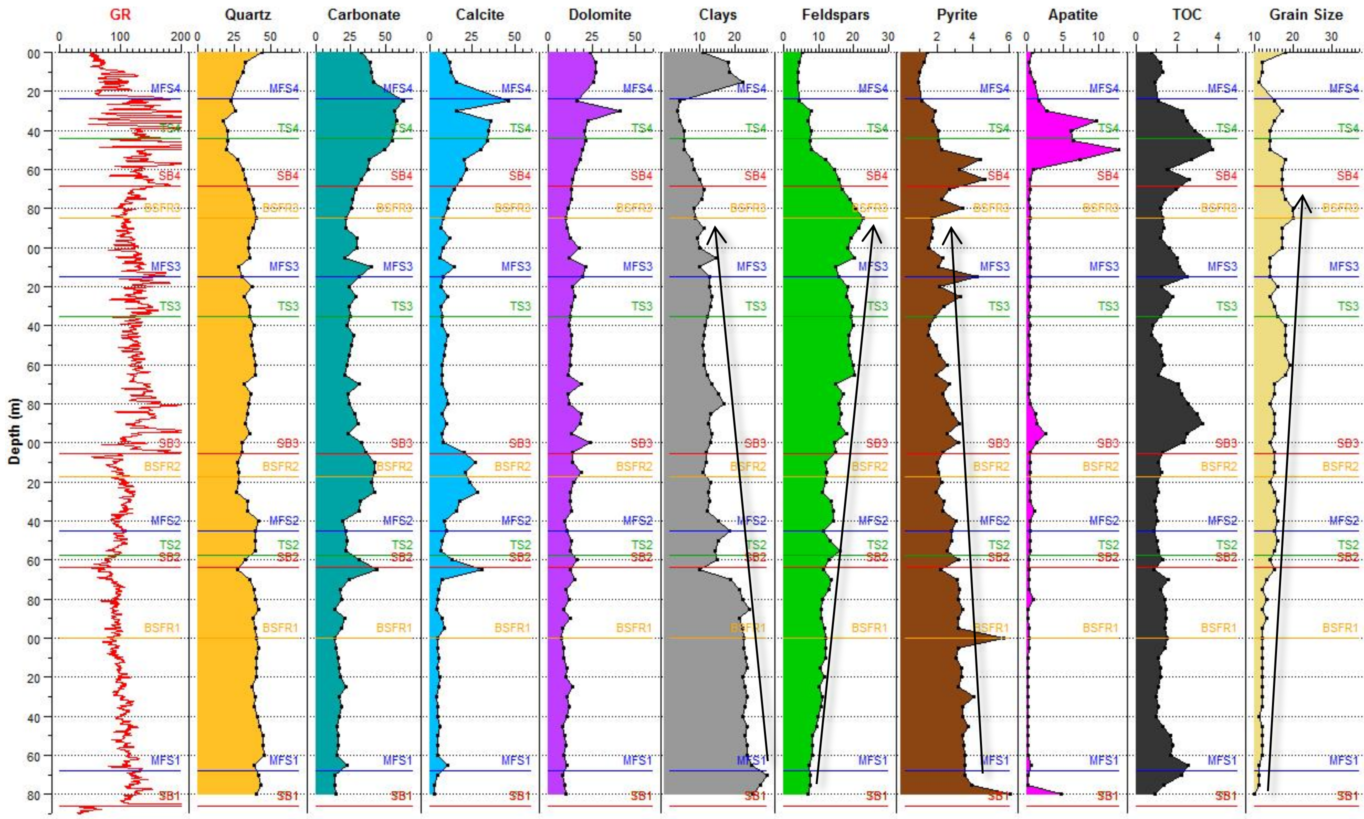

Figure1: Gamma Ray curve (left track), mineralogy (weight%), TOC , and sequence stratigraphic surfaces of the studied well over the Montney Formation and Doig Phosphate.

Petrophysical analysis

The quantitative well log analysis was performed by Robert V. Everett Petrophysics Inc (Fig. 2). The main steps of the petrophysical workflow are summarized here below:

- Normalize calculated minerals by constraining with the log elements and measured GR spectroscopy (K, U, Th), to convert the Si & K to quartz, K-feldspar, plagioclase and muscovite; Ca to dolomite, calcite and anhydrite (via sulphur); Si, Al, K and Fe to illite, smectite, kaolinite and chlorite. This first process involves a model derived from 600 cores. This process was repeated using Robust Elm in GAMLS (Eslinger and Boyle 2013). The Robust ELM method does not involve a pre-determined model but makes one from the data, providing an excellent fit to cuttings in the Montney.

- Solve for porosity and permeability using the Herron formulas (Herron et al 1998) involving the log elements and the calculated carbonate, clay and siliclastics.

- Solve for Sw and provide estimates of irreducible (SWIRR) and minimum water saturation (SW_DS_GAS_ECS, Nieto et al 2009) to estimate if water will be produced:

- Determine Rw from the SP. The Rw derived from the SP was calibrated to a catalog value of 0.1@77F. The SP fluctuations allowed propagation of the Rw to the top of the well (Everett 2014).

- Calculate the total organic carbon (TOC) by clustering with the measured TOC and the resulting best fit was used.

Results of the petrophysics are displayed on Fig. 2. The model mineralogy (ELM) compares closely with the cuttings data and provides robust input for petrophysical calculation (matrix density, surface area and cation exchange capacity). CMR-derived porosity (TCMR) matches routine core analyses from the three available cores. Computed permeability is one to two orders of magnitude lower than routine core analysis data.

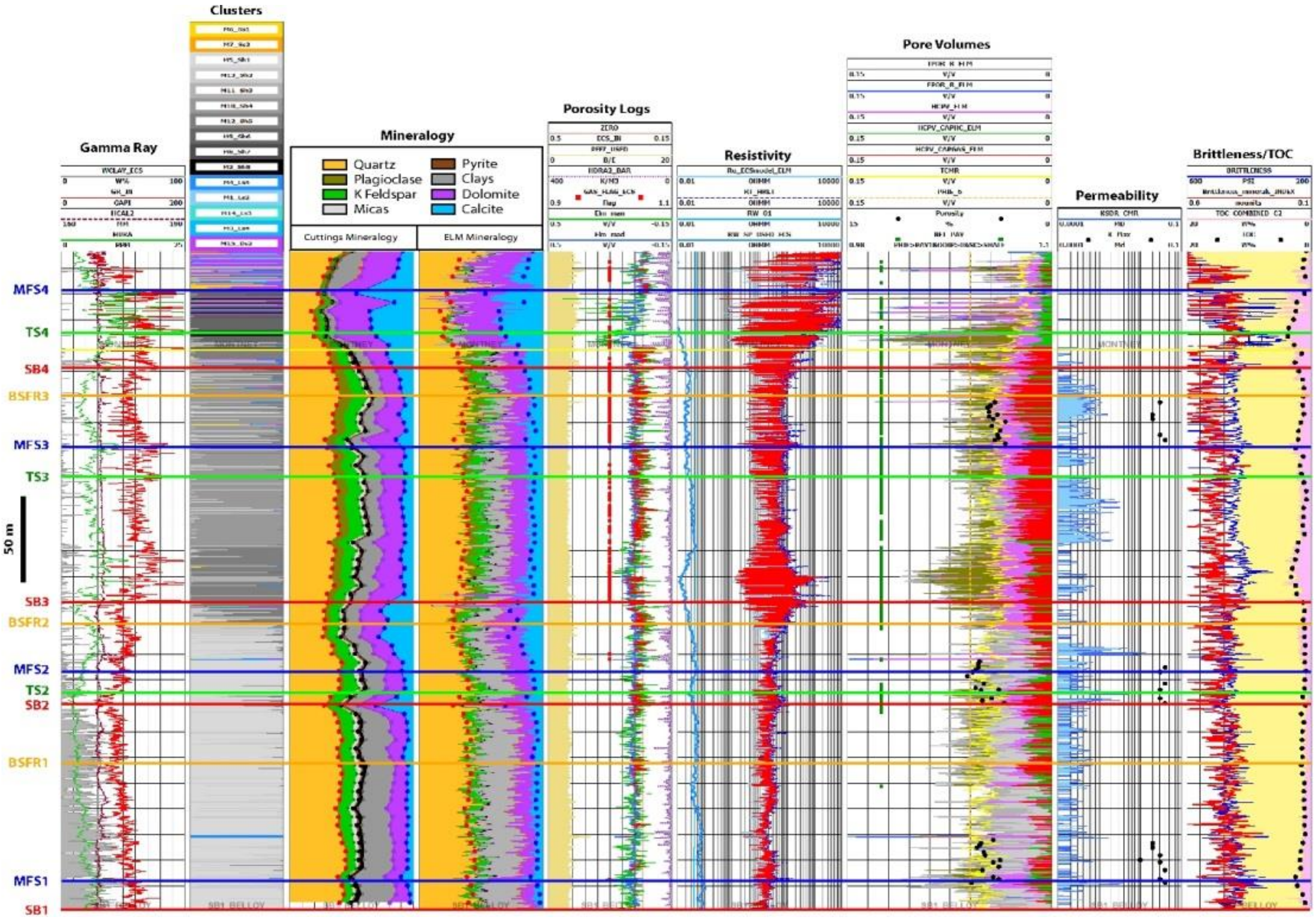

Figure 2: Quantitative log analysis of the studied well over the Montney Formation and Doig Phosphate.

Preliminary results:

Based on our preliminary results, the following observation can be made:

- Sequence 1 shows higher water saturation than sequences 2 and 3, but it is likely to be clay bound water (Fig. 2, grey shading, track 7).

- The three zones with the highest total porosity correspond to organic rich intervals. However, some of this porosity is probably of organic origin and these intervals have low CMR derived permeability.

- The difference between the density-derived total porosity and the CMR-derived porosity maybe associated with the presence of bitumen (Fig. 2, olive shading, track 7)

- The brittleness trends derived from the dipole sonic and from the mineralogy do not agree and further investigation is needed to understand this discrepancy.

Acknowledgements

The authors would like to thank Jamie Everett, Ramdane Bouchou and Eric Eslinger for their technical support. We thank Progress Energy Canada Ltd. for giving us access to their huge database on the studied well. We also thank Ramona Jones for her useful style and typo corrections.

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