

Preliminary Fluid Flow Assessment and Diagenetic Impacts on Hydrocarbons within the Duvernay Formation, WCSB, Alberta

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Summary

This research aims to characterise organic matter in the mixed hydrocarbon (oil-dry gas, oil-condensate) producing areas of the Late Devonian Duvernay Formation in Alberta (Canada) by high-resolution RockEval data (n=246) and petrography (n=35) at three drillhole locations (Location A and C distal, Location B proximal to Leduc Reef, respectively). Further stable isotope (C and O) analysis on diagenetic calcite and dolomites (n = 50) identified during petrography were interpreted to understand the potential source and diagenetic effects of fluid flow during the thermal evolution of organic matter within the Duvernay Formation.

Introduction

Canada is recognised as a major player in the development of unconventional hydrocarbon reservoirs, producing more than 160 thousand barrels per day (kb/d) of “tight oil” in 2012, with an estimated 500 million barrels of oil (MMBO) of reserves (Atchley et al., 2006). The primary focus of unconventional resource exploration is within the Devonian to Cretaceous aged strata of the Western Canada Sedimentary Basin (Alberta Geological Survey, 2012). Within the past four years, there has been a significant increase in exploration activities focusing on the Frasnian Duvernay Formation; a known source rock for conventional petroleum resources in overlying reservoir rocks of the Leduc Reef complex (Atchley et al., 2006; Dunn et al., 2012). The Leduc Reef reservoirs contain reserves of up to 250 MMBO in place, migrated from the Duvernay Formation (Dembicki et al., 2013). Much of these secondary hydrocarbons are still considered trapped as “unconventional” or “tight oil” within the Duvernay Formation (Rokosh et al., 2010a; Cioppa et al., 2002). Despite the importance of the Duvernay Formation in conventional petroleum systems, and its significant potential as a tight oil and gas producer, the kerogen type and distribution, thermal history and reservoir potential are poorly understood (Bustin et al., 2010; Rokosh et al., 2010a).

Perhaps of the greatest concern to current exploration is the irregularity of hydrocarbon production within the Duvernay Formation (Rokosh et al., 2012). Despite well-constrained thermal boundaries, wells produce “mixed” hydrocarbons (i.e. oil and condensate, condensate and dry gas), with a different thermal signature than those found in the overlying conventional reservoirs (Bustin et al., 2010; Rokosh et al., 2010a). These hydrocarbon variabilities reveal a discontinuity between the current understanding of the Duvernay Formation and its behavior as an unconventional hydrocarbon producer. In order to fully exploit its promising economic potential, the organic matter in the Duvernay Formation in hydrocarbon producing regions must be characterised. A recent study acknowledging irregularity in production by Wüst et al. (2013) emphasises the need for further research into the reasons for inequivalence between thermal maturity data.

The thermal maturation of organic matter within the basin coincides with the development of the Laramide Orogeny in the Early Cretaceous (Bustin, 1991; Alberta Geological Survey, 2010), though subsequent

thermal events are not regionally understood (Fowler and Grasby, 2006; Porter et al., 1982). Under conventional models, the thermal maturity of the kerogen within the Duvernay ranges from immature in the NE, to dry gas window in the SW (Dieckmann et al., 2004; Majorowicz and Moore, 2014; Alberta Geological Survey, 2010; Vandenbroucke and Largeau, 2007). Fluid flow appears to have caused positive anomalies in thermal maturity in the Western Canadian Sedimentary Basin (Fowler and Grasby, 2006). These fluid flow events are thought to have occurred in relatively recent geological history (approx. Eocene) during basin uplift and may have some link to irregular maturation, or to diagenesis linked to mixed hydrocarbon production in the Duvernay Formation (Fowler and Grasby, 2006; Maowen et al., 1997).

Theory and/or Method

The three wells sampled for this study were drilled in 2012, during the most recent generation of exploration in the region of Townships 62 (Location A and C) and 63 (Location B). The well at Location A intersected the Duvernay Formation at depths from 2989.0 to 3035.0 m (46 m thickness). At Location B the Duvernay Formation was intersected from 3340.5 – 3387.5 m (48 m thickness), and at Location C intersected from 3792.8 – 3800.8 (8 m thickness). The Duvernay Formation was sampled in each of these wells with an aim to investigate any changes in the character of the formation, with samples obtained at intervals ranging from 20 cm to 1 m, with each sample having a thickness of ~ 1 cm. A total of 246 samples over the three cores were collected and analysed to produce a high-resolution data set.

For petrography samples were crushed to a 1–2 mm fraction; epoxy impregnated, ground and polished following ATSM Standard D7708-11. Samples were viewed under oil immersion using a 50x objective, using an incident light Zeiss Axioimage II microscope system equipped with fluorescent light sources and the Discus-Fossil system for the reflectance measurements. Bitumen reflectance ($BR_0\%$) was measured and statistically appraised using Fossil Software, and later converted to equivalent vitrinite reflectance using the Bertrand formula (Bertrand et al., 1990).

A subset of samples were then analysed for thermal and hydrocarbon parameters using RockEval 6. Another subset of these samples were selected for isotope (C and O) analysis of carbonates. Isotope values were sequentially extracted from calcites (low temperature CO₂ release) and dolomites (>500C CO₂ release). The produced CO₂ gas was isolated in a mass spectrometer and their C and O isotopes analysed. Data was corrected for drift using University of Calgary Stable Isotope Lab standards (CAL-I, CAL-II, CAL-III; calcites), BaSO₄, and international standards LSVEC (Li₂CO₃) and NBS19 (limestone).. The total data set was then compiled and appropriate statistics applied to draw correlations between variation in secondary mineral precipitation and thermal irregularities within samples.

Results and Discussion

At all locations reported values for S1 varied widely over depth, ranging from 0.13 – 9.37 mg HC/g, with no observable trend. S1 values greater than >3.5 mg HC/g may represent possible contamination from drilling or cleaning fluids from core recovery. Total Organic Carbon (TOC) ranges from 0.15 – 6.22 % wt at Location A, 0.43 – 8.20 % wt at Location B, and 1.84 – 5.23 % wt at Location C, with an overall median value of 3.42 % wt consistent with other organic rich shales (Araujo et al., 2014). S2 values range from 0.20 – 7.42 mg HC/g at Location A, 0.22 – 4.23 mg HC/g at Location B, and 1.68 – 5.04 % at Location C, respectively. S2 hydrocarbons correlate positively ($R^2 = 0.95$) with total organic carbon (TOC) throughout the sampled interval at all three locations (Badics and Vető, 2012). Both TOC and S2 exhibit well-developed, peaks then decreases at both a small (~2.5 m, $\Delta TOC \sim 1.5\%$) and large (~15.0 m, $\Delta TOC \sim 3.5\%$) resolution at Locations A and B. At Location C TOC and S2 both remain constant throughout the sampled interval. The results for samples from all locations indicate Kerogen type is Type I to Type II, consistent with other marine deposited, Devonian shales (Araujo et al., 2014). The results

obtained from RockEval analysis and petrography indicates a contradiction between the apparent thermal maturity determined by RockEval and equivalent vitrinite reflectance. A recent publication by Wüst et al. (2013) also identified discrepancies between evaluated T_{\max} data for the Duvernay Formation, and calculated vitrinite reflectance values from organic petrography. Converted vitrinite reflectance (Bertrand et al., 1990) at all sample locations had a mean value of 1.12 % with a standard deviation of 0.093 %. At Location A the mean vitrinite reflectance was 1.08% ($\sigma = 0.052$), at Location B mean vitrinite reflectance was 1.13% ($\sigma = 0.097$) and at Location C mean vitrinite reflectance was 1.25% ($\sigma = 0.052$).

The $\delta^{13}\text{C}$ for dolomite and calcite show little variation between a minimum of -0.9 ‰ and maximum of 0.6 ‰. The $\delta^{18}\text{O}$ data shows a wider range of variation, with calcite values between -10.8 and -7.4 ‰, and dolomite values between -12.7 and -4.2 ‰. Carbon isotopes of both dolomites and calcites suggest they were mineralised prior to hydrocarbon generation within the Duvernay Formation as their $\delta^{13}\text{C}$ values are well constrained between -1.0 and +1.0. If these carbonates were to be mineralized syn- or post-kerogen maturation (beginning at $\sim 60^\circ\text{C}$), $\delta^{13}\text{C}$ would be expected to fall within the organic isotope range (-27 to -23 ‰), assuming *in situ* fluids formed these carbonates (Qing et al., 2006). More than half of the samples analysed ($n = 17$) have $\delta^{13}\text{C}$ values that fall below the range of calcites and dolomites formed by Devonian seawaters (0 to +2.0 ‰) (Al-Aasm et al., 2002). Using a palaeothermometry relationship established by Anderson and Arthur (1983), the formation temperature of the calcite within the Duvernay Formation samples may be established using $\delta^{18}\text{O}$ data. Calculated formation temperatures from $\delta^{18}\text{O}$, strongly agree with converted bitumen reflectance values determined from organic petrography, therefore suggesting there was little to no carbon in these carbonates sourced from organic material despite synformation of hydrocarbons.

Conclusions

The mixed hydrocarbon signatures exhibited by the Duvernay Formation present a challenge when assessing the Formation for its economic potential. This research has outlined some of the factors, which have influenced this mixed recovery and unequivalent thermal maturation indicators, including vitrinite reflectance, T_{\max} and palaeothermometry results. It is concluded from the RockEval and petrographic results in two separate regions of the Duvernay Formation, that post-depositional, diagenetic effects (e.g. TSR, BSR or others) are likely the cause of altered hydrocarbons and mineralisation. In order to further test and validate these conclusions, $\delta^{34}\text{S}$ values of organic matter and sulfides (Aizenshtat and Amrani, 2004), will be determined to shed further light on the most likely geochemical reactions and pathways causing the observed alterations. Using stable isotopes of C and O of carbonates (both dolomite and calcite) within the Duvernay Formation it was possible to define both the fluid source and formation temperatures. $\delta^{18}\text{O}$ and $\delta^{13}\text{C}$ both indicated a Devonian seawater fluid source of pore waters, of which resulted in precipitation of calcites and dolomites at temperatures from 59 – 83°C, within the oil generation window. More positive $\delta^{13}\text{C}$ within the oil window may indicate low temperature enrichment of ^{13}C by methanogenic or sulfate reducing bacteria.

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